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Impact of Natural Gas Shortage on Major Industrial Fuel-Burning Installations
Volume I. Text

Foster Associates, Inc, Washington, D C Energy Div

Prepared for

Environmental Protection Agency, Research Triangle Park, N C Strategies and Air Standards Div

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IMPACT OF NATURAL GAS SHORTAGE ON MAJOR INDUSTRIAL FUEL-BURNING INSTALLATIONS - VOLUME I. TEXT

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Waste Management
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

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16. ABSTRACT

This study was conducted to analyze the impact of natural gas shortages on major fuel burning installations. The analysis consisted of the review of gas curtailments plans, natural gas supplies, FEA survey data for MFBI and applicable state air pollution control regulations. This analysis estimated the availability of natural gas through 1980 for major fuel burning installations, the alternate fuel burning capability of these plants, the need for alternate fuels such as fuel oil and coal to offset the gas shortages and the estimated increase in sulfur dioxide and particulate emissions from the burning of these alternate fuels. The study results are presented in a three volume report: the first contains the narrative for the analysis of natural gas shortages on the gas fired plants with pertinent findings and conclusions; the second contains schedules or data summaries for the natural gas fired plants; and the third presents a limited analysis of all the MFBI data.

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VOLUME ONE

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INTRODUCTION

The end result of this study is an estimate of the incremental emissions of sulfur dioxide and particulate matter from major industrial gas combustors resulting from gas supply inadequacy between 1976 and 1980. To reach this end result, three separate but nonetheless interrelated analyses were performed. Natural gas supply and demand were projected for 1087 industrial plants containing major gas combustors; at plants where gas shortages were projected, the use of alternative fuels by type was estimated; and reflecting the use of the alternative fuels, increases in emissions of sulfur dioxide and particulate matter were calculated based upon federally enforceable air pollution regulations. Natural gas is the cleanest burning fossil fuel, containing negligible sulfur and ash compared with coal and fuel oil. Thus, as a result of the gas shortage, emissions of sulfur dioxide and particulate matter will be higher than if more gas were available.

Data on the fuel-burning characteristics of the gas combustors dealt with in this study were obtained from a 1975 survey of large, primarily industrial fuel-burners conducted by the Federal Energy Administration (FEA). Included in the category of industrial plants are some Federal, state and local facilities as well as a few universities and hospitals. Specifically excluded from this study are electric utility power plants and a few liquefied-natural-gas and synthetic-natural-gas facilities owned by gas utilities. The results of the FEA survey were made available to Foster Associates through the Environmental Protection Agency.

The FEA survey was intended primarily for determining the coal-burning potential of industrial combustors; the FEA questionnaire was entitled "Major Fuel Burning Installation Coal Conversion Report." The coverage of this study reflects the limitations of the FEA survey. FEA requested data on 1973/1974 fuel consumption and the capability to burn alternate fuels only for combustors with a heat input capacity of at least 100 million Btu per hour. This means that the data which the surveyed plants reported to FEA were not designed to reveal the plant's total fuel use, total gas use, nor total capability to burn alternate fuels; it also means that surveyed plants which had no combustor of the capacity described did not report any fuel use or alternate fuels capability. Since, however, gas use in large combustors would normally be curtailed first and the large combustors represent the larger potential polluters, this study provides a good estimate of potential increases in pollutant emissions through 1980.

The following table summarizes the coverage of the industrial sector represented by the major[1] gas burning MFBI analysed herein. Column (2) shows the number of major gas burning MFBI in each state; Column (3) shows gas consumption in the major gas combustors of those MFBI; Column (4) shows the percent of total industrial gas consumption in that state represented by the major gas combustors; Column (5) shows the total fossil fuel consumption (gas, fuel oil and coal) in the major gas combustors of these MFBI; and Column (6) shows the percent of total industrial fossil fuel consumption in that state represented by the major gas combustors. The regional totals in Columns (4) and (6) indicate the percent of total industrial gas consumption and total industrial fossil fuel consumption in that region represented by major gas combustors.

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[1] A major MFBI is one which contains at least one combustor with a capacity of 100 MMBtu/hr.

Summary Table 1
Sheet 1 of 2

COMPARISON OF GAS AND TOTAL FOSSIL FUEL CONSUMPTION OF MAJOR GAS BURNING MFBI WITH TOTAL INDUSTRIAL GAS AND FOSSIL FUEL CONSUMPTION BY STATE IN 1974

EPA Region/State (1)	Gas Consumption of Major MFBI: Number of Plants (2)	Gas Consumption of Major MFBI: Trillion Btu's (3)	Gas Consumption of Major MFBI: Percent of Total Industrial Gas Consumption (4)	Fossil Fuel Consumption by Major Gas Consumers a/: Trillion Btu's (5)	Fossil Fuel Consumption by Major Gas Consumers a/: Percent of Total Industrial Fossil Fuel Consumption (6)
Region I					
Connecticut	3	1	5.68	1	1.25
Massachusetts	10	6	12.7	9	4.6
Maine	--	--	--	--	--
New Hampshire	2	1	74.5	1	7.7
Rhode Island	--	--	--	--	--
Vermont	1	a/	3.2	--	a/
Total	16	8	10.0	11	7.9
Region II					
New Jersey	13	14	21.1	27	11.1
New York	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	21	[illegible]	[illegible]	[illegible]
Region III					
District of Columbia	--	--	--	--	--
Delaware	3	1	20.5	1	12.9
Maryland	11	14	22.7	28	17.6
Pennsylvania	43	52	14.7	150	21.6
Virginia	14	9	16.5	16	6.9
West Virginia	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Region IV					
Alabama	26	48	25.9	107	39.1
Florida	21	31	55.8	60	17.7
Georgia	24	32	19.5	60	25.5
Kentucky	21	13	17.5	26	17.0
Mississippi	16	55	50.7	68	54.2
North Carolina	22	12	13.8	10	15.5
South Carolina	26	23	29.1	50	22.0
Tennessee	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Region V					
Minnesota	21	29	28.8	36	21.5
Wisconsin	28	26	18.9	12	15.3
Michigan	59	115	33.1	151	30.1
Ohio	56	107	26.6	160	20.3
Illinois	60	96	25.4	163	26.0
Indiana	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Region VI					
Arkansas	13	40	10.5	55	23.6
Louisiana	78	466	40.8	486	40.6
New Mexico	4	8	25.5	10	24.2
Oklahoma	18	67	32.9	67	40.5
Texas	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Region VII					
Iowa	25	30	25.5	41	23.1
Kansas	15	26	16.9	32	20.2
Missouri	17	20	22.1	34	22.7
Nebraska	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

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Summary Table 1
Sheet 2 of 2

COMPARISON OF GAS AND TOTAL FOSSIL FUEL CONSUMPTION OF MAJOR GAS BURNING MFBI WITH TOTAL INDUSTRIAL GAS AND FOSSIL FUEL CONSUMPTION BY STATE IN 1974

EPA Region/State (1)	Number of Plants (2)	Gas Consumption by Major MFBI: Trillion Btu's (3)	Gas Consumption by Major MFBI: Percent of Total Industrial Gas Consumption (4)	Fossil Fuel Consumption by Major Gas Combustors a/: Trillion Btu's (5)	Fossil Fuel Consumption by Major Gas Combustors a/: Percent of Total Industrial Fossil Fuel Consumption (6)
Region VIII					
Colorado	28	31	30.5%	39	71.3%
Montana	11	16	62.2	19	32.2
North Dakota	1	1	27.0	2	12.6
South Dakota	1	1	0.5	1	0.9
Utah	10	20	35.1	30	61.6
Wyoming	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	60	104	[illegible]	141	[illegible]
Region IX					
Arizona	10	20	60.9	36	67.5
California	89	186	31.7	212	28.9
Nevada	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	101	210	[illegible]	251	[illegible]
Region X					
Idaho	10	10	31.6	16	29.0
Oregon	17	14	25.2	21	21.5
Washington	[illegible]	[illegible]	[illegible]	77	[illegible]
Total	62	84	[illegible]	113	[illegible]
Total Lower 48 States	1,087	2,871	33.0%	3,784	29.4%

a/ Excludes fossil fuel consumption by non-gas combustors of gas burning MFBI.

b/ Negligible.

As shown on the table, gas consumption by the major gas combustors represents one-third of total industrial gas consumption in the Lower 48 States.[1] Many of these combustors also consume other fuels, and the major gas combustors represent 29 percent of total industrial fossil fuel consumption. Coverage varies significantly by EPA Region, representing only 10 percent of Region I's industrial gas consumption and 12 percent of Region II, but ranging as high as 49 percent in Region VI, 44 percent in Region X, and 53 percent in Region VIII.

The results of this study are summarized in the immediately succeeding section. Following the Summary are the texts of Chapters I, II, III and IV, respectively detailing the gas supply and demand forecasts, the alternative fuel use estimates, the emission calculations and background information on national and regional gas situations. The schedules of data described in Chapters I to IV are contained in Volume Two. Volume Three is an appendix which analyzes and summarizes the data pertaining to the fuel consumption characteristics of not only gas burning combustors but also combustors which do not consume gas.

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[1] Unfortunately there are no data on the gas or energy consumption of the combustors with capacity less than 100 MMBtu/hr. at these 1087 plants. These plants probably consume nearly as much gas in smaller combustors as in the larger. Thus it is estimated that these 1087 plants may be responsible for between one-half and two-thirds of total industrial gas consumption in the U.S.

SUMMARY

This study projects a severe and worsening shortage of natural gas in the United States to 1980. In the aggregate, industrial gas consumption will decline sharply between 1974 and 1980, and gas shortages will steadily rise at the 1087 industrial plants analyzed in this study. Both boilers and other types of combustors, even some without existing alternate fuel capabilities will be affected. To maintain operations, industrial plants will have to use alternate fuels. Consequently, emissions of sulfur dioxide and particulate matter will increase.

This study projects by plant the annual gas shortages, associated use of alternative fuels, and resultant emission increases from 1976 to 1980. These estimates are displayed and calculated to reflect the net increase over 1974 levels. Thus, the volumetric gas shortages for 1976 to 1980 do not include any shortages which may have existed in 1974, the base year; the amount of alternative fuel use projected equates to the amount of gas shortage and thus does not include the volume of alternative fuels which was used in 1974 by these combustors; and the emissions are the incremental increase over 1974 levels as a result of the gas shortage.

The table on the following two pages summarizes the projected gas shortages in major MFBI gas combustors by state and EPA Region.

Summary Table [illegible]
Sheet 1 of 2

PROJECTED GAS SHORTAGES IN MAJOR [illegible] GAS COMBUSTORS BY STATE,
1976 - 1980
(Trillions of Btu's)

FEA Region/State	1976 Gas Consumption	Shortages 1976	1977	1978	1979	1980
Region I						
Connecticut	0.5	0.3	0.3	0.4	0.5	0.5
Massachusetts	5.9	1.4	1.2	1.4	1.8	1.9
Maine	--	--	--	--	--	--
New Hampshire	0.7	--	--	--	--	--
Rhode Island	--	--	--	--	--	--
Vermont	0.1	--	--	--	--	--
Total	[illegible]	1.6	1.5	1.8	[illegible]	[illegible]
Region II						
New Jersey	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
New York	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Region III						
Delaware	[illegible]	0.1	0.3	0.2	0.3	0.3
Maryland	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Pennsylvania	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Virginia	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
West Virginia	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Region IV						
Alabama	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Florida	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Georgia	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Kentucky	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Mississippi	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
North Carolina	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
South Carolina	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Tennessee	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	100.5	111.0	[illegible]
Region V						
Illinois	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Indiana	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Michigan	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Minnesota	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Ohio	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Wisconsin	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Region VI						
Arkansas	60.0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Louisiana	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
New Mexico	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Oklahoma	[illegible]	--	--	--	--	--
Texas	[illegible]	--	--	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Region VII						
Iowa	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Kansas	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Missouri	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Nebraska	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	87.7	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Summary Table 2
Sheet 3 of 3

PROJECTED GAS SHORTAGES IN MAJOR NFBI GAS COMBUSTORS BY STATE, 1976 - 1980

(Trillions of Btu's)

EPA Region/State	1974 Gas Consumption	Shortages 1976	1977	1978	1979	1980
Region VIII						
Colorado	31.6	--	1.1	2.0	2.9	3.7
Montana	15.9	7.6	9.9	10.2	10.5	10.9
North Dakota	0.9	0.4	0.4	0.4	0.5	0.5
South Dakota	0.6	0.4	0.6	0.6	0.6	0.6
Utah	27.8	2.0	--	--	1.6	3.6
Wyoming	27.1	1.7	1.2	2.6	4.4	6.0
Total	103.9	12.1	13.2	15.8	20.5	25.3
Region IX						
Arizona	28.0	8.3	11.1	15.0	16.8	17.5
California	185.7	10.1	40.7	56.6	79.6	82.9
Nevada	2.1	0.2	0.3	0.3	0.3	0.3
Total	215.8	18.6	52.1	71.9	96.7	100.7
Region X						
Idaho	9.7	--	--	--	n/	n/
Oregon	14.7	--	0.7	1.2	1.2	0.5
Washington	61.0	5.4	6.9	8.3	7.9	7.4
Total	85.4	5.4	7.6	9.5	9.1	7.9
Total Lower 48 States	2,870.7	203.4	308.1	405.0	512.9	611.9

Note: In some cases the projected shortage can exceed actual 1974 consumption due to increased demand.

n/ Negligible.

The first column of data shows the 1974 gas consumption of major MFBI gas combustors by state, followed by the projected gas shortages annually from 1976 to 1980. For example, in Connecticut, major MFBI gas combustors consumed 0.9 trillion Btu's in 1974, and the gas shortage in these combustors is expected to be 0.3 trillion Btu's in 1976 increasing annually to 0.5 trillion Btu's in 1980. The shortages shown reflect the arithmetic difference between supply of and demand for gas by these combustors.

For all major MFBI combustors in the U.S., the volumetric gas shortage is shown to triple between 1976 and 1980. These growing shortages reflect the compounded effect of declining supplies and increasing demand.

Demand for gas by major combustors at MFBI is tied to projections of economic activity and overall industrial energy demand for the Nation in the aggregate. For purposes of this study, demand for gas at MFBI is calculated to reflect the same trend as industrial demand for energy in general.

The gas supply forecasts for individual plants are situation specific, and reflect available public information. Overall, however, it was assumed that conventional gas production from wells in the Lower 48 States would continue to decline to 1980 but the rate of decline would be lower than that experienced in 1974 and 1975 due to a projected increase in new supply. Since onshore exploration for gas has increased substantially in response to the rapid rise in intrastate field prices, and since it is assumed that offshore drilling will increase due to the recent rise in interstate price levels for new gas, an increase in reserves additions compared to the last few years is forecast. The projections also incorporate supplemental gas (LNG, SNG from liquid hydrocarbons and Canadian gas), but not in sufficient volume to offset the shortage.

The gas supply and demand forecasts were constructed on an annual basis assuming normal weather. Moreover, it was assumed that gas companies will have sufficient storage and peaking capacity to meet all residential and small commercial requirements under these weather conditions. To the extent that weather is abnormally cold, as it has been during the 1976-1977 winter, the industrial gas shortages will be even more severe. Although there may be sufficient gas on an annual basis to cover an industrial plant's needs, unexpected capacity and supply difficulties can occur and cause substantial economic dislocation which is not reflected or analyzed in this study. This study assumes that all gas shortages are offset by consumption of alternative fuels, as shown by the table on the following two pages which summarizes the increased use of alternative fuels by state and EPA Region.

Column (2) shows the annual average alternative fuel use, which equates to the annual average gas shortage. Columns (3) through (6) depict the percent distribution of this alternative fuel use among residual oil, distillate oil, coal and other (primarily LPG). For example, in Connecticut, increased alternative fuel use will average 0.4 trillion Btu's per year in major MFBI combustors to make up for the

Summary Table 4
Sheet 1 of 2

THE DISTRIBUTION OF ALTERNATIVE FUEL USE BY TYPE AS A RESULT OF GAS SHORTAGES IN MAJOR NFBI GAS COMBUSTORS BY EPA REGION AND STATE

1976 - 1980

EPA Region/State (1)	Annual Average Alternative Fuel Use (Trillions of Btu's) a/ (2)	Percent Distribution by Fuel Type: Residual (3)	Distillate (4)	Coal (5)	Other (6)
EPA Region I					
Connecticut	0.4	98.25	1.75	--	--
Massachusetts	1.5	100.0	--	--	--
Maine	--	--	--	--	--
New Hampshire	--	--	--	--	--
Rhode Island	--	--	--	--	--
Vermont	--	--	--	--	--
Total	1.9	99.2	0.8	--	--
EPA Region II					
New Jersey	4.0	100.0	--	--	--
New York	1.1	85.5	14.5	--	--
Total	5.1	96.9	3.1	--	--
EPA Region III					
Delaware	0.3	100.0	--	--	--
Maryland	5.1	36.4	63.6	--	--
Pennsylvania	13.2	68.9	26.5	4.75	--
Virginia	6.8	72.6	11.2	16.2	--
West Virginia	1.6	38.5	33.1	28.4	--
Total	27.0	66.1	25.8	8.1	--
EPA Region IV					
Alabama	13.1	72.6	3.8	23.6	--
Florida	12.7	73.2	25.8	--	1.0
Kentucky	5.9	37.6	49.1	13.3	--
Georgia	6.6	77.9	5.9	16.2	--
Mississippi	10.9	66.2	28.7	--	5.1
North Carolina	10.3	83.1	7.6	9.3	--
South Carolina	5.3	80.7	6.8	12.5	--
Tennessee	25.6	30.5	31.8	37.7	--
Total	90.1	66.3	19.6	13.4	0.7
EPA Region V					
Illinois	75.9	67.8	7.0	19.7	5.5
Indiana	19.6	60.9	8.2	30.7	0.2
Michigan	21.1	37.9	18.6	43.5	--
Minnesota	5.1	74.1	15.8	10.1	--
Ohio	26.3	62.5	25.7	11.8	--
Wisconsin	4.0	43.3	47.6	9.1	--
Total	152.1	57.6	17.3	23.7	1.4
EPA Region VI					
Arkansas	10.5	82.8	17.2	--	--
Louisiana	13.1	66.9	32.5	--	0.6
New Mexico	2.0	91.9	8.1	--	--
Oklahoma	--	--	--	--	--
Texas	32.8	36.6	63.4	--	--
Total	58.4	52.5	47.4	--	0.1
EPA Region VII					
Iowa	7.1	22.7	21.4	55.9	--
Kansas	6.8	75.0	0.8	24.2	--
Missouri	6.5	75.0	3.8	21.2	--
Nebraska	0.8	--	100.0	--	--
Total	21.2	54.1	12.8	33.1	--

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Summary Table 3
Sheet 3 of 3

THE DISTRIBUTION OF ALTERNATIVE FUEL USE BY TYPE AS A RESULT OF GAS SHORTAGES TO MAJOR [illegible] GAS CONSUMERS BY EPA REGION AND STATE
1976 - 1980

EPA Region/State (1)	Annual Average Alternative Fuel Use (Trillions of Btu) a/ (2)	Percent Distribution by Fuel Type: Residual (3)	Distillate (4)	Coal (5)	Other (6)
EPA Region VIII					
Colorado	[illegible]	[illegible]	[illegible]	[illegible]	--
Montana	[illegible]	[illegible]	[illegible]	--	--
North Dakota	[illegible]	100.0	--	--	--
South Dakota	[illegible]	100.0	--	--	--
Utah	[illegible]	[illegible]	[illegible]	--	--
Wyoming	[illegible]	[illegible]	[illegible]	--	--
Total	[illegible]	[illegible]	[illegible]	[illegible]	--
EPA Region IX					
Arizona	[illegible]	[illegible]	[illegible]	[illegible]	--
California	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Nevada	[illegible]	--	100.0	--	--
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
EPA Region X					
Idaho	b/	--	b/	b/	--
Oregon	[illegible]	[illegible]	[illegible]	[illegible]	--
Washington	[illegible]	[illegible]	[illegible]	--	--
Total	[illegible]	[illegible]	[illegible]	[illegible]	--
Total Lower 48 States	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

b/ Negligible.

a/ Equates to annual average gas shortage from 1976 - 1980.

annual average gas shortage of an equal amount. Residual oil is shown to comprise 96.3 percent of this increased fuel use in Connecticut.

For the Nation as a whole, residual oil is depicted as making up for 61.4 percent of the gas shortage, distillate oil for 25.5 percent, coal for 12.5 percent, and other for 0.6 percent. Considerable diversity occurs by plant, state and region. Residual oil is the predominant alternative to gas in many states, and coal use is dominant only in Michigan, Iowa, and Colorado. Distillate oil is dominant in Kentucky, Wisconsin, Texas, Nebraska, Montana, Utah and Nevada.

The selection of alternative fuels to gas at MFBI was based on what the individual plants reported as of the end of 1974. In cases where a combustor had no existing alternate fuel capability, conversion to the fuel used by similar plants was assumed.

The table on the following two pages sets out the projected annual alternative fuel use by type in conventional units.

Summary Table 6
Sheet 1 of 2

ANNUAL AVERAGE INCREASE IN ALTERNATIVE FUEL USE AS A RESULT OF GAS SHORTAGES IN MAJOR NPNI GAS CONSUMERS EXPRESSED IN CONVENTIONAL UNITS

1976 - 1980

	Residual Oil (Thousands of Barrels) (1)	Distillate Oil (Thousands of Barrels) (2)	Coal (Thousands of Tons) (3)	LPG (Thousands of Barrels) (4)
EPA Region I				
Connecticut	61	3	--	--
Massachusetts	238	--	--	--
Maine	--	--	--	--
New Hampshire	--	--	--	--
Rhode Island	--	--	--	--
Vermont	--	--	--	--
Total	300	3	--	--
EPA Region II				
New Jersey	632	--	--	--
New York	149	87	--	--
Total	781	87	--	--
EPA Region III				
Delaware	32	--	--	--
Maryland	655	380	--	--
Pennsylvania	1,562	195	25	--
Virginia	786	531	44	--
West Virginia	404	90	18	--
Total	3,439	1,196	87	--
EPA Region IV				
Alabama	2,003	149	400	--
Florida	1,672	961	--	31
Kentucky	326	499	31	--
Georgia	820	67	63	--
Mississippi	1,139	516	--	--
North Carolina	1,303	133	39	138
South Carolina	681	62	27	--
Tennessee	1,287	1,225	173	--
Total	10,457	3,333	833	169
EPA Region V				
Illinois	2,081	299	198	343
Indiana	1,980	273	250	41
Michigan	1,202	683	376	--
Minnesota	606	137	21	--
Ohio	2,530	1,081	117	--
Wisconsin	674	360	16	--
Total	9,078	2,833	978	384
EPA Region VI				
Arkansas	1,987	312	--	--
Louisiana	1,304	720	--	21
New Mexico	290	28	--	--
Oklahoma	--	--	--	--
Texas	1,807	3,690	--	--
Total	4,878	4,750	--	21

ANNUAL AVERAGE INCREASE IN ALTERNATIVE FUEL USE AS A RESULT OF GAS SHORTAGES IN MAJOR NPGI GAS CONSUMERS EXPRESSED IN CONVENTIONAL UNITS

1976 - 1980

	Residual Oil (Thousands of Barrels) (1)	Distillate Oil (Thousands of Barrels) (2)	Coal (Thousands of Tons) (3)	LPG (Thousands of Barrels) (4)
EPA Region VII				
Iowa	229	203	101	--
Kansas	1,080	12	95	--
Missouri	519	29	37	--
Nebraska	--	182	--	--
Total	1,828	466	284	--
EPA Region VIII				
Colorado	119	32	60	--
Montana	649	983	--	--
North Dakota	78	--	--	--
South Dakota	80	--	--	--
Utah	6	222	--	--
Wyoming	448	88	--	--
Total	1,379	1,325	60	--
EPA Region IX				
Arizona	1,198	961	48	--
California	5,944	2,360	112	69
Nevada	--	30	--	--
Total	7,142	3,351	160	69
EPA Region X				
Idaho	--	1	a/	--
Oregon	106	2	2	--
Washington	784	612	--	--
Total	890	615	2	--
Total Lower 48 States	30,140	17,881	3,063	596

Btu Contents: Residual 6,287,000 Btu/Bbl; Distillate 5,825,000 Btu/Bbl; Coal 24,835,000/ short ton; LPG 4,011,000 Btu/Bbl.

a/ Negligible.

Summary Table 5 on the following two pages shows the projected annual average incremental emissions of sulfur dioxide and particulate matter resulting from gas shortages to major combustors at the 1087 MFBI from 1976 through 1980 by state. The annual average incremental increase in sulfur dioxide emissions for the total Lower 48 States is shown to be 370 thousand tons per year, as compared with 48 thousand tons per year of particulate matter. The areas with the greatest increases are of course those with the greatest gas shortages, as well as those with more lenient emission regulations. Nearly 40 percent of the total increase in emissions is attributable to Region IV, while 20 percent is attributable to Region V and 11 percent to Region IX.

The emission increases were calculated assuming that fuels substituted for gas would emit at the maximum allowable level as stipulated in the applicable federally enforceable regulations. A brief summary of the results of this study organised by EPA Region, is set out following the table.

Summary Table 5
Sheet 1 of 2

ANNUAL AVERAGE INCREMENTAL EMISSIONS OF SULFUR DIOXIDE AND PARTICULATES AS A RESULT OF GAS SHORTAGES IN MAJOR MFBI GAS CONSUMERS BY STATE

1976 - 1980

(Tons Per Year)

EPA Region/State (1)	Sulfur Dioxide (2)	Particulates (3)
Region I		
Connecticut	111	39
Massachusetts	1,012	90
Maine	--	--
New Hampshire	--	--
Rhode Island	--	--
Vermont	--	--
Total	1,123	129
Region II		
New Jersey	612	218
New York	371	50
Total	983	268
Region III		
District of Columbia	--	--
Delaware	32	49
Maryland	1,923	269
Pennsylvania	7,626	1,121
Virginia	6,980	363
West Virginia	4,029	63
Total	20,590	2,044
Region IV		
Alabama	26,907	1,252
Florida	13,064	522
Kentucky	8,271	615
Georgia	11,359	1,001
Mississippi	26,272	1,654
North Carolina	11,651	1,705
South Carolina	9,268	671
Tennessee	34,107	3,171
Total	140,899	10,591
Region V		
Illinois	13,887	1,127
Indiana	15,330	2,068
Michigan	13,486	1,953
Minnesota	5,256	1,387
Ohio	19,300	1,337
Wisconsin	4,652	3,396
Total	71,911	11,268
Region VI		
Arkansas	8,512	330
Louisiana	24,108	3,897
New Mexico	941	16
Oklahoma	--	--
Texas	7,564	1,872
Total	41,125	6,114
Region VII		
Iowa	12,360	1,860
Kansas	11,512	996
Missouri	6,094	615
Nebraska	1,180	13
Total	31,146	3,484

Summary Table 1
Sheet [illegible] of [illegible]

ANNUAL AVERAGE INCREMENTAL EMISSIONS OF SULFUR DIOXIDE AND PARTICULATES AS A RESULT OF GAS SHORTAGES IN MAJOR NFBI GAS COMBUSTORS BY STATE

1976 - 1980

(Tons Per Year)

EPA Region/State (1)	Sulfur Dioxide (2)	Particulates (3)
Region VIII		
Colorado	867	124
Montana	4,907	1,983
North Dakota	893	89
South Dakota	839	84
Utah	1,093	236
Wyoming	1,095	383
Total	9,903	2,708
Region IX		
Arizona	6,160	586
California	29,510	10,354
Nevada	28	8
Total	35,698	10,948
Region X		
Idaho	6	2
Oregon	632	120
Washington	7,594	680
Total	8,232	802
Total Lower 48 States	369,900	68,153

Region I

The incremental increases in sulfur dioxide and particulate emissions are minimal in Region I, projected at 1.1 and 0.1 thousand tons per year, respectively. Region I is heavily dependent on fuel oil, and gas supplied only 5 percent of the total energy consumed by all major combustors in this region in 1974. Residual fuel oil is expected to be substituted for virtually all gas shortfalls. However, the incremental increase in alternate fuels for Region I represents less than 1 percent of the total increase in alternate fuel consumption for the Lower 48. Roughly half of the Region I increases are concentrated in the Boston AQMA.

Region II

The projected annual increases in emissions are also relatively small in Region II -- 1.0 thousand tons of sulfur dioxide and 0.3 thousand tons of particulate. Region II is similar to Region I in that residual fuel oil is the major source of energy for large combustors. Also, the sample accounts for only about 11 percent of industrial gas consumed in these regions, indicating that most gas is consumed in smaller combustors. Another factor influencing the low emission levels in these two regions is that emission regulations are relatively stringent. The New Jersey-New York AQMA accounts for nearly three-fourths of all incremental emissions projected for Region II, with the lion's share attributable to the New Jersey portion.

Region III

The annual increases in Region III are projected at 21 thousand tons per year of sulfur dioxide and 2 thousand tons per year of particulate, 5 percent of the Lower 48 total increase. Gas shortages are projected to average 27 trillion Btu's per year, approximately one-third of the region's gas consumption by major combustors in 1974. Fuel oil will be substituted for 25 of the 27 trillion Btu shortfall. Nearly 80 percent of the emissions increases in Region III are from Pennsylvania and Virginia. Substantial increases are forecast for the Petersburg-Colonial Heights-Hopewell AQMA in Virginia, as well as the Southwest Pennsylvania AQCR.

Region IV

Gas consumption by major MFBI combustors is projected to decline by 41 percent in Region IV from the 1974 level of 254 trillion Btu's. This severe decline will necessitate the substitution of some 99 trillion Btu's per year of alternate fuels -- 66 trillion Btu's of residual fuel oil, 20 trillion Btu's of distillate fuel oil, and 13 trillion Btu's of coal. It is estimated that the substitution of these fuels for gas will increase sulfur dioxide emissions by 150 thousand tons per year, and particulate emissions by 11 thousand tons per year. The fact that alternate fuel consumption in Region IV represents 24 percent of the Lower 48 total but sulfur dioxide emissions represent 40 percent of the Lower 48 total is indicative of the generally more lenient emission regulations in these 8 states. Nearly half of the estimated emissions increases are forecast for Alabama and Tennessee.

Three AQMA in Region IV are shown to have sulfur dioxide emissions in excess of 5 thousand tons per year: Birmingham, Mobile and Savannah. Relatively high sulfur dioxide emissions are also forecast for 3 AQCR: Mobile-Pensacola-Panama City-Southern Mississippi (36 thousand tons per year); Metro Memphis (21 thousand tons per year); and East Tennessee (15 thousand tons per year).

Region V

The gas consumption by major MFBI combustors in Region V is projected to decline by 25 percent over the forecast period, from 457 trillion Btu's in 1974 to 342 trillion Btu's in 1985. This heavily industrialized region accounts for 20 percent of all Lower 48 emissions, 72 thousand tons per year of sulfur dioxide, and 11 thousand tons per year of particulates. The estimated particulate emissions are greater for Region V than any other region, as the incremental coal consumption in Region V represents nearly half of the Lower 48 total. Over half of the estimated emissions in 1976 are attributable to the state of Ohio. Total emissions increases (both sulfur dioxide and particulate) are notably high in a number of AQMA: Cincinnati (10 thousand tons per year); Detroit (12 thousand tons per year); and Illinois - Indiana - Wisconsin (21 thousand tons per year). The latter AQMA is predominantly within the metropolitan Chicago area.

Region VI

Although Region VI accounted for 54 percent of the total 1974 MFBI gas consumption in the Lower 48 States it is projected to account for only 11 percent of the incremental increase in emissions -- 41 thousand tons per year of sulfur dioxide and 6 thousand tons per year of particulates. Although significant declines in gas consumption are forecast for Arkansas and New Mexico, consumption is projected to remain fairly stable in Texas and Louisiana, and increases in industrial gas consumption are expected in Oklahoma. In the latter years of the forecast significant increases are expected in a number of AQMA in Texas, including Beaumont, Corpus Christi, and Houston as a partial boiler fuel phaseout mandated by the Texas Railroad Commission is implemented. Other AQMA with noticeable increases are Little Rock (4 thousand tons of sulfur dioxide and particulates per year) and Shreveport (8 thousand tons of sulfur dioxide and particulates per year).

Region VII

The 25 percent decline in gas consumption by major combustors in Region VII is shown to produce 31 thousand tons in additional sulfur dioxide emissions per year and 3 thousand tons in additional particulate emissions per year. Approximately 33 percent of the total energy supplied by alternate fuels in Region VII is projected to come from coal, as compared with only 11 percent for the rest of the Nation. Four trillion Btu's of the 7 trillion Btu annual increase in additional coal consumption is attributable to Iowa, and this state accounts for over 40 percent of the Region's total increase in emissions. The greatest average annual increases in emissions for AQMA in Region VII are in Kansas City -- 6 thousand tons per year of sulfur dioxide and 0.6 thousand tons per year of particulate.

Region VIII

It is estimated that emissions of sulfur dioxide will increase by 10 thousand tons per year as a result of gas shortages to major combustors in Region VIII, and particulate emissions will increase by 3 thousand tons per year. Over half of the increase in sulfur dioxide emissions and 60 percent of the increase in particulate emissions are attributable to Montana, as it is expected that the significant portion of gas previously exported from Canada to Montana will sharply decline. The AQMA with the greatest expected increases in emissions is Anaconda-Butte, with average annual sulfur dioxide increases of 2.8 thousand tons per year and particulate emissions of 1.1 thousand tons per year.

Region IX

The increase in sulfur dioxide emissions in Region IX is forecast at 36 thousand tons per year, about 10 percent of the Lower 48 total, and the increase in particulate emissions is forecast at 11 thousand tons per year, 23 percent of the Lower 48 total. The fact that Region IX accounts for 17 percent of the Lower 48 annual increase in alternate fuel consumption but only 10 percent of the increase in sulfur dioxide emissions is indicative of the relatively strict sulfur dioxide emission regulations in California. Over 80 percent of the total energy of all major MFBI combustors in Region IX was supplied by gas in 1974, and the 44 percent decline in gas supply by 1980 will result in an increase in alternate fuel consumption of 68 trillion Btu's per year.

Of this 68 trillion Btu's per year, 64 trillion Btu's will be supplied by fuel oil. Two AQMA in California, Kern County and South Coast, account for nearly half of the average annual increase in emissions.

Region X

Gas consumption by major MFBI combustors is projected to decline by only 1 percent by 1980 in Region X, and thus incremental increases in emissions are expected to be relatively small. Total increases in emissions are projected to average 9 thousand tons per year, 8 thousand tons of sulfur dioxide and 1 thousand tons of particulates, roughly 2 percent of the Lower 48 total. Over 90 percent of the total emissions forecast are for Washington, and the Puget Sound AQMA is shown to emit about half of the Region's increase in both sulfur dioxide and particulates.

CHAPTER I

GAS DEMAND AND SUPPLY PROJECTIONS FOR MAJOR MFBI GAS COMBUSTORS

The purpose of this chapter is to discuss the methodology underlying the gas demand and supply projections for individual major gas combustors at MFBI and to summarize the results. In the last chapter of this study a more thorough analysis of the national and regional gas supply outlook is provided. The reader should also be referred to "The Impact of Gas Curtailments on Electric Utility Plants," prepared by Foster Associates in 1975 for EPA, which among other things contains a detailed discussion of curtailment plans by gas pipelines and distributors.

The gap between gas supply and demand at each MFBI is a shortage, which requires the burning of alternate fuels, which in turn generates emissions of sulfur dioxide and particulate matter. Since the alternative fuel use projected in this study is estimated by equating the alternative fuel needs in Btu's, with the heat content of the gas shortfall in Btu's, the emissions which are the end result of this study are quite sensitive to the gas supply and demand projections.

Initially discussed below is the basis for the demand projections used in this study, followed by a general description of the methodology underlying the gas supply projections. It should be recognized that greater effort has been expended in the analyses of supply compared to demand. This chapter concludes with a discussion and explanation of the regional, state and local gas supply and shortage projections.

Determination of Demand for Gas by Major MFBI Gas Combustors

There are a large number of variables which as a practical matter will result in somewhat different trends in the demand for gas in the various combustors at each of the 1087 plants analyzed. These variables include the price and availability of alternate fuels and expectations thereof; weather; output of manufactured goods and thus demand for the products of the plants; and conservation efforts within these plants. However, such individual plant analyses are beyond the scope of this study. For purposes herein, demand for gas by major combustors at MFBI is tied to projections of economic activity and overall industrial energy demand for the Nation in the aggregate.

Demand for gas at these industrial plants is calculated to reflect the same trend as industrial demand for energy in general. On the basis of heat content, natural gas is generally priced lower than alternate fuels in most industrial markets, and if sufficient supply were available at these prices gas consumption would increase relative to other fuels. However, the incremental emissions measured herein are from combustors which used gas in 1973 or 1974, and do not include those emissions which would have been avoided if sufficient gas were available to penetrate new markets.

A number of regressions, linear, log-linear and non-linear, were attempted relating industrial energy consumption to various economic indices of industrial activity as well as to wholesale energy prices. Dummy variables were in some instances employed to accommodate the impact of conservation which first appeared during the oil embargo. As hypothesized, the most significant variable explaining changes in industrial energy consumption is the level of industrial economic activity, measured by the Federal Reserve Board Index of Industrial Production. The addition of other variables does not improve the statistical significance of the equation nor does it substantially change the relationship between industrial production and industrial energy consumption.

Industrial energy demand from 1975 to 1980 is estimated by reference to industrial production, in log-linear form. The base year is 1974, and thus the forecast incorporates substantial conservation. As well, continuing conservation albeit at a modest rate is implicit in the forecast, and the rate of increase in demand is reduced by ten percent to reflect continuing conservation effects. This ten percent adjustment does not appreciably affect the results, as by 1980 demand would be only one percent higher without the ten percent adjustment. For purposes of projections, industrial production (the FRB index, excluding electric power generation) is assumed to increase by ten percent in 1976 and at a four percent annual rate thereafter.

The following table compares the forecast with the historical experience.

COMPARISON OF INDUSTRIAL ENERGY DEMAND AND THE FEDERAL RESERVE BOARD INDEX OF INDUSTRIAL PRODUCTION

	FRB Index[a/] (1967 = 100.0)	Industrial Energy Consumption (Trillions of Btu's)
1961	66.8	16,198
1962	72.4	16,840
1963	76.7	17,869
1964	81.8	18,602
1965	89.3	19,184
1966	98.1	19,815
1967	100.0	19,965
1968	105.5	21,297
1969	110.3	22,172
1970	105.6	22,460
1971	105.5	22,394
1972	113.8	23,020
1973	124.2	24,042
1974	123.4	23,033
1975	111.7	21,657
1976	121.8	22,864
1977	126.6	23,365
1978	131.7	23,889
1979	137.0	24,426
1980	142.4	24,964

a/ Excludes electric utilities.

From 1961 to 1973, industrial production increased at an annual average rate of 5.3 percent. Between 1970 and 1971 the sole decline during the period occurred, and that was less than 0.1 percent. The maximum year to year increase of 9.9 percent occurred in 1966. During the entire 12-year period, industrial consumption of energy increased at an annual average rate of 3.3 percent. Consistent with the trend in industrial production, energy consumption declined only once -- in 1971 -- but at a rate of 0.8 percent.

From 1973 to 1975, both industrial production and industrial energy consumption declined markedly. Industrial production declined 0.6 percent in 1974 and 9.5 percent in 1975. Industrial energy consumption declined 4.2 percent in 1974 and 6.0 percent in 1975. It is hypothesized that a significant and lasting conservation effect was experienced during this time.

The forecast assumes a 10 percent rise in industrial production for 1976 and 4 percent per year thereafter, with the former possibly being optimistic in light of more recent economic results and projections, and the latter being slightly lower than historical rates. Industrial energy demand is projected to increase by 5.6 percent in 1976 and approximately 2.2 percent per year thereafter. Until 1979, industrial demand for energy is projected to be below the 1973 peak.

The range in possible industrial demand for gas to 1980 is not nearly as great as the range in possible industrial gas supply, as there is substantially more uncertainty in the supply forecasts than in the demand projections. However, a change in the levels of demand forecast in this study, all other things being equal, would alter the projected volume of shortage, alternative fuel use and emissions. For example, nationally, if gas demand by MFBI was unchanged between 1974 and 1980, the projected shortage in 1980 would be reduced by 40 percent, as would be projected alternative fuel use and emissions. A 10 percent increase in demand over what is projected herein to 1980 would increase the projected shortage, alternative fuel use and emissions by 51 percent in 1980.

Comparison of the MFBI Supply Forecasts with Other Studies

The volume of gas consumed by the industrial sector declined substantially in 1974 and 1975. Most forecasts suggest further reductions through 1980 but not as severe on an annual basis as these recent declines. For example, between 1974 and 1980, the Department of Interior forecasts a 9 percent decline in overall gas supply and a 10 percent decline in industrial gas consumption, while the Gas Requirements Committee (GRC) forecasts a comparable decline in overall gas supply and a 23 percent decline in industrial gas consumption. While other studies do not project industrial gas consumption, they generally project declining overall gas supply to 1980. The independent analyses prepared for this study also confirm this general outlook.[1]

Among the available sources, only GRC provides projections of industrial gas consumption by state and year to 1980. The GRC projections of industrial gas consumption are displayed on Schedule I-1. The following table compares the percent decline in industrial gas consumption between 1974 and 1980 by state from GRC with the decline herein projected for major MFBI gas combustors.

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[1] Chapter IV contains a thorough discussion of the national supply outlook, including a more detailed review of available forecasts of gas supply.

COMPARISON OF THE INDUSTRIAL GAS CONSUMPTION FORECASTS IN THIS STUDY WITH THE GRC FORECASTS BY STATE

FEA Region/State (1)	Percent Change Between 1976 and 1980 This Study (2)	 GRC (3)
Region I		
Connecticut	(47)%	(21)%
Massachusetts	(41)	(2)
Maine	--	5
New Hampshire	6	1
Rhode Island	--	(3)
Vermont	39	3
Total Region I	(35)	(8)
Region II		
New Jersey	(23)	(32)
New York	(5)	(4)
Total Region II	(18)	(11)
Region III		
Delaware	(21)	(61)
Maryland	(33)	(36)
Pennsylvania	(22)	(27)
Virginia	(75)	(56)
West Virginia	(5)	(32)
Total Region III	(26)	(31)
Region IV		
Alabama	(55)	(10)
Florida	(37)	(69)
Georgia	(23)	(36)
Kentucky	(66)	(35)
Mississippi	(19)	(35)
North Carolina	(96)	(54)
South Carolina	(25)	(22)
Tennessee	(64)	(56)
Total Region IV	(41)	(52)
Region V		
Illinois	(38)	(12)
Indiana	(31)	(28)
Michigan	(17)	(13)
Minnesota	(19)	(35)
Ohio	(17)	(36)
Wisconsin	(33)	(20)
Total Region V	(25)	(23)
Region VI		
Arkansas	(21)	(11)
Louisiana	5	(32)
New Mexico	(22)	1
Oklahoma	8	76
Texas	(1)	(9)
Total Region VI	0	(18)

COMPARISON OF THE INDUSTRIAL GAS CONSUMPTION FORECASTS IN THIS STUDY WITH THE GRC FORECASTS BY STATE

EPA Region/State (1)	Percent Change Between 1976 and 1980 This Study (2)	 GRC (3)
Region VII		
Iowa	(26)%	(28)%
Kansas	(38)	(30)
Missouri	(21)	(20)
Nebraska	(6)	(30)
Total Region VII	(25)	(27)
Region VIII		
Colorado	(3)	1
Montana	(60)	(52)
North Dakota	(50)	(55)
South Dakota	(94)	(66)
Utah	(5)	(26)
Wyoming	(16)	(20)
Total Region VIII	(16)	(23)
Region IX		
Arizona	(56)	(38)
California	(63)	(18)
Nevada	(8)	(25)
Total Region IX	(56)	(20)
Region X		
Idaho	8	12
Oregon	5	7
Washington	(6)	(1)
Total Region X	(1)	3
Total Lower 48 States	(13)%	(21)%

Note: Brackets denote negative.

The foregoing table shows that for the total Lower 48 States, GRC projects a more severe decline (23 percent) than this study projects for major gas combustors (13 percent). However, this apparent divergence nationally is primarily attributable to differences in the forecasts for EPA Region VI, comprised of the following states: Arkansas, Louisiana, New Mexico, Oklahoma and Texas. With state-to-state variation, GRC projects an 18 percent decline in industrial gas consumption in Region VI while this study projects essentially no change in the availability of gas for major combustors.

It should be recognized, however, that the coverage of this study does not extend to the entire industrial sector but rather pertains to large combustors at specific plants. The gas supply outlook for plants not analyzed herein can differ from these projections. For example, the MFBI in Louisiana were served by intrastate suppliers to a greater extent than the state as a whole, and it is the interstate pipelines which have substantially reduced deliveries in Louisiana.

As stated previously, the advantage of the GRC forecast is its detail, which facilitates comparison with the results of this study. The GRC forecast of gas consumption by sector and state is the composite of projections by the individual gas distributors and pipelines serving particular markets and thus it reflects the respondents' assessments of future gas supply. With regard to Federal, state and local policies concerning price regulation, allocations, priorities of service and other factors which might affect future consumption patterns by sector, the data reflect individual distributors' own evaluations. There may be different outlooks for the gas supply available to be sold to industrial customers in various areas of a state served by more than one distributor and/or pipeline.

The GRC reports were extremely useful in the preparation of this study. As a starting point for all projections, the GRC forecasts were reviewed for each state. In a few instances, the GRC industrial gas consumption projections were directly applied to the MFBI. The following section describes the procedures underlying the MFBI supply forecasts.

Gas Supply Assumptions and Methodology

For individual MFBI the specific supply forecasts were developed by using publicly available data related to: gas supply nationally; individual industrial plants; and the gas distributors and pipelines serving these plants. Key general assumptions with regard to gas supply are listed below.

1) It was assumed that normal weather would prevail from 1976 to 1980. Colder than normal weather would not only increase gas demand for industrial space-heating but also reduce the supply of gas available for industrial consumption. Residential-small commercial demand is normally regarded as the first-priority commitment by sellers of gas (and regulatory authorities) and is satisfied out of available supply before industrial sales are made. With colder than normal weather, such as that which has occurred to date during the 1976/1977 winter, industrial gas supply would be lower than herein projected because of higher residential-commercial consumption. Moreover, to satisfy high

priority needs, gas companies are withdrawing substantial volumes of gas from storage which will have to be replenished during the ensuing summer at the expense of industrial gas sales.

2) It was assumed that conventional gas production from wells in the Lower 48 States would continue to decline to 1980 but the rate of decline would be lower than that experienced in 1974 and 1975 due to a projected increase in new supply. Since onshore exploration for gas has increased substantially in response to the rapid rise in intrastate field prices, and since it is assumed that offshore drilling will increase due to the recent rise in interstate price levels for new gas, an increase in reserves additions is forecast.

More specifically, the supply forecasts used herein reflect an approximate 10 percent increase in 1976 and 20 percent increase thereafter in new supply attachments, compared to their 1972-1975 experience, by major interstate pipelines. It is assumed that no further write-downs in estimates of existing proved reserves or deliverability therefrom will occur. Most of the increase in new reserve attachments by interstate pipelines are projected to be in the Gulf of Mexico. Thus, there is considerable diversity in the projected reserves additions for various interstate pipelines, reflecting their relative accessability to offshore reserves.

Without any new reserves, total interstate pipeline supply would decline at an annual rate of over 10 percent. The foregoing assumptions regarding reserves additions reduce the annual rate of decline to approximately 4 percent.

3) The forecasts also reflect supplemental gas (LNG, SNG from liquid hydrocarbons, and Canadian gas) but not in sufficient volume to offset the projected shortage. Most supplemental gas projects have experienced delays and are not expected to be onstream before 1980.

With respect to LNG, it is assumed that two major projects, primarily benefiting certain states in EPA Regions I, II, III, IV and V, will be operational. The Eascogas project, bringing Algerian LNG to EPA Regions I and II, is assumed to be onstream in mid-1978 at scheduled volumes. The First El Paso LNG project, which will import 1 Bcf/d of Algerian LNG to be purchased by the Columbia Gas System, Consolidated Gas Supply and Southern Natural Gas is also expected to be onstream in 1978.

With respect to SNG from liquid hydrocarbons, no new plants are assumed. Plants which were built by the end of 1976 are projected to be the only sources of SNG available through 1980. Thus, no coal-gasification plants are forecast to be in operation. The output from existing SNG plants is consumed entirely in EPA Regions I, II, III and IV.

Canadian gas, which currently accounts for 5 percent of U.S. gas supply, is projected to remain nearly constant to 1980 and thus remain the largest single category of supplemental gas. Existing export licenses are expected to be met but upon expiration of their term, are assumed to be phased out. Canadian gas is important in EPA Regions V, VIII, IX and X.

4) The Federal Power Commission has instituted procedures (Order 533) whereby industrial gas users who need gas for processes in which only gas is feasible can purchase gas directly in the field at above-ceiling rates and have this gas transported by interstate pipelines.[1] Through November 15, 10 of the MFBI had received approval for these arrangements. In 9 of the 10 plants, however, the gas is dedicated to combustors with capacity less than 100 MMBtu/hr. Thus, the volumes authorized under Order 533 arrangements will have no impact on the shortages projected for the larger combustors (all boilers) in the nine plants which are analysed by this study. There is one MFBI which has obtained Order 533 gas for process combustors over 100 MMBtu/hr., and this study assumes that demand at this plant will be met beyond the two year term of authorization.

Order 533 procedures can and will alleviate some of the gas shortages in process combustors of MFBI. Unfortunately, it is impossible to forecast which MFBI will be the beneficiaries of such arrangements in the future.

The outlook for specific MFBI was developed by researching a host of publicly available material and converting this material into a forecast. Initially, the types of sellers of gas -- distributors or pipelines -- to the MFBI had to be estimated. Over 10 percent of the MFBI purchase gas directly from interstate pipelines, and in these cases the type of contract -- firm or interruptible -- could be ascertained from

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[1] Chapter IV contains a detailed discussion of Order 533 arrangements.

Form 2's filed by the relevant interstate pipelines. In the remainder of cases, the MFBI received gas from distributors who in turn buy from interstate pipelines or, in gas producing states, the MFBI received gas through intrastate pipelines. It is not possible to ascertain with certainty the type of contract involved in these cases.

The next step was to investigate the supply circumstances of the relevant sellers of gas within the states. Helpful guides to the immediate outlook for individual states, pipelines and distributors were Projected Natural Gas Curtailment and Potential Needs for Additional Alternate Fuels, FEA; the FPC Staff reports on the Winter Impact of Natural Gas Curtailments with Respect to Nineteen Individual Pipeline Companies prepared in FPC Docket Nos. RP75-116, *et al.*; Form 16's and 69's filed by interstate pipelines with the FPC; and FPC summary reports on the curtailment situations of interstate pipelines.

For the longer term outlook with respect to individual sellers of gas, a number of sources were reviewed to assess not only the gas supply outlook but also the marketing and/or curtailment strategies of the gas companies involved. The available sources of information vary in usefulness from company to company but include Annual Reports to Stockholders, Form 10K's filed with the SEC, prospectuses and hearings before and decisions of state and Federal regulatory authorities. Taking into account the national gas supply perspective previously described, individual pipeline supply forecasts were generated reflecting deliverability from existing reserves as of January 1, 1976 plus an allowance for LNG, SNG and projected new reserves additions.

The above research essentially confirmed the GRC industrial forecasts for some states. If there was no apparent regional diversity within the state in these instances, the MFBI forecasts were developed by trending the GRC projections forward from 1974 actual data. In other cases independent industrial gas consumption projections were constructed.

Projected Gas Consumption and Shortages by AQCR and AQMA

The purpose of this section is to summarize the individual MFBI gas consumption and shortage projections. Schedule I-2 shows the forecast by region, state, AQCR and AQMA. It is important to bear in mind that this and all subsequent schedules summarizing the MFBI pertain only to the designated large combustors burning gas, and do not necessarily represent the entire industrial sector in any state. Moreover, the annual volumetric shortages displayed on the schedule do not include any shortages which may have existed in 1974, the base year. The derivation of the shortages reflects the arithmetic difference between demand and supply, in other words the net increase in the shortages over 1974 levels. The AQMA on the schedule are shown below the AQCR in which they fall and are indented and preceded by a dash.

EPA Regions I and II

Gas consumption by major combustors in EPA Regions I and II (New England, New York, and New Jersey) totaled 26 trillion Btu's in 1974, less than 1 percent of gas consumption in all major combustors in the Lower 48 States. This low percentage representation reflects the predominant use of alternate fuels by the industrial sector in these regions as well as the predominant use of gas in combustors with a capacity less than 100 MMBtu/hr. Gas consumption by major combustors represented only 11 percent of total industrial gas consumption in these regions.

Overall, gas consumption by major MFBI combustors in Regions I and II is projected to decline but the rate of decline will be reduced due to supplemental gas. A number of SNG plants are already operating in these areas and LNG is assumed to be available beginning in 1978. Most of the MFBI gas consumption is in New Jersey, and these MFBI are largely served by the particular distributors who have obtained additional gas supplies. The southern New Jersey glass industry which is experiencing considerable difficulties is not represented at all in the data.

EPA Region III

In EPA Region III -- consisting of Delaware, Maryland, Pennsylvania, Virginia and West Virginia -- major industrial combustors consumed 97 trillion Btu's of gas in 1974. Over half of this gas was used in Pennsylvania, particularly in the Metro Philadelphia AQMA and the Southwest Pennsylvania AQCR. The states in this region are served by a number of different interstate pipelines, all of which have been curtailing deliveries to their distributor customers. Transcontinental Gas Pipeline (Transco), which is curtailing deliveries more severely than most other interstate pipelines, serves Delaware and parts of Virginia and Pennsylvania. Columbia Gas Transmission, although curtailing conventional gas supplies, has been able to partially offset the impact of these curtailments through the sale of SNG. Columbia, which serves Maryland and West Virginia as well as parts of Virginia and Pennsylvania, anticipates the purchase of substantial LNG volumes beginning in 1978. Pennsylvania is also served in important degree by Consolidated Gas Supply and Texas Eastern Transmission. Over a third of West Virginia's gas supply is from wells within the state.

A steep decline in gas consumption between 1974 and 1976 is projected for Region III, but supply is shown as essentially stable thereafter. This reflects the projections for essentially stable supply to 1980 for some of the pipelines serving the region as well as the introduction of LNG. Also, emergency relief has been granted to the U.S. Steel plants in Southwest Pennsylvania, which consume significant volumes of gas for process purposes. Another important factor is that minimal residential growth is projected in this region, which means that as long as overall supply is stable, industrial supply will remain the same.

The most significant declines are projected for Virginia, reflecting the fact that a number of MFBI in this state are indirectly served by Transco. Continued declines in overall supply are projected for this pipeline. Although Transco is an important supplier to other states in this region, and also Region II, few of the MFBI herein analyzed are indirectly served by this pipeline.

EPA Region IV

In EPA Region IV -- consisting of Alabama, Florida, Kentucky, Georgia, Mississippi, North Carolina, South Carolina, and Tennessee -- major industrial combustors during 1974 consumed 254 trillion Btu's of gas. This volume represents 9 percent of gas consumption by all major industrial combustors in the Lower 48 States. All of the states in this region consume substantial volumes of gas in large industrial combustors, led by Mississippi with 55 trillion Btu's.

A number of pipelines sell gas in this region, and each state has a different supply and demand situation. Overall, MFBI gas consumption is projected to decline by 28 percent between 1974 and 1976 and by a further 18 percent between 1976 and 1980. Because demand increases, the shortage is projected to nearly double between 1976 and 1980. Both declining supply for the pipelines serving this region and increasing consumption by residential and commercial customers in many states contribute to the declining availability of gas for industrial users. It should be noted as well that a number of the MFBI in this region purchase gas directly from interstate pipelines.

MFBI in Alabama are served primarily by Southern Natural Gas, both indirectly and directly. In addition, Alabama-Tennessee Natural Gas and United Gas Pipe Line Co. make direct sales of gas to a number of MFBI in the state. Overall gas supply for the state is projected to decline, but the impact on the industrial sector will be even more severe as residential-commercial growth is projected. Southern Natural will import LNG beginning in 1978, offsetting in part the declines in conventional supply. It is assumed that United will not have sufficient gas to make any sales to MFBI after 1977, and that Alabama-Tennessee will have phased out its interruptible sales by 1978.

Florida is served primarily by Florida Gas Transmission, although United makes a few direct sales to MFBI in the northern part of the state. The projections reflect an end to boiler fuel sales by United after 1977 and a substantial reduction in 1976 deliveries by Florida Gas Transmission, but slightly increasing thereafter.

Kentucky is served primarily by Texas Gas Transmission but also receives substantial volumes of gas from Columbia Gas Transmission and Tennessee Gas Pipeline (Tenneco). A very substantial decline through 1978 is projected for both overall gas supply and industrial gas consumption; after 1978 continued but more modest declines are forecast. No residential-commercial growth is projected. Absent this assumption, the projections of industrial gas supply would be more pessimistic.

Georgia is served largely by Southern Natural and partially by Transco. As with Alabama, this state will receive substantial volumes of LNG beginning in 1978. However, when coupled with substantial residential-commercial growth which is expected, the overall supply situation will result in declining industrial gas supply. Particularly hard hit will be the direct industrial boiler fuel customers of Southern Natural Gas which is curtailing deliveries under an end-use plan.

Mississippi is served by a large number of pipelines, but over half of the MFBI with major gas combustors purchase gas directly from United. No residential-commercial growth is projected. Nonetheless, the forecast shows a substantial decline in gas consumption, reflecting the rapid phase-out of boiler fuel sales by United. With respect to the gas combustors without alternate fuel capabilities using gas for process purposes, it has been assumed that sufficient supply will be available to meet requirements.

North Carolina is served by Transco, and the virtual cessation of boiler fuel consumption by MFBI is projected. While some of the MFBI have made Order 533 arrangements for process combustors, these combustors are not large enough for coverage herein.

Over two-thirds of South Carolina is served by Southern Natural, with the remainder served by Transco. The research herein confirmed the outlook projected by GRC, and hence the MFBI projections reflect the GRC forecast.

Tennessee is served largely by Tennessee Gas Pipeline and Texas Gas Transmission. Although minimal residential-commercial growth is projected, industrial gas supply is forecast to steadily decline as overall supply declines. The complete elimination of boiler fuel use in markets served by Texas Gas Transmission (particularly Memphis) and by MFBI served directly by other pipelines is projected after 1977. One MFBI in this state with large process combustors has obtained Order 533 gas.

There are a number of AQCR and AQMA in Region IV which will experience large volumetric shortages. The Mobile-Pensacola-Panama City-Southern Mississippi AQCR, located in Mississippi, Florida and Alabama, will experience shortages of over 30 trillion Btu's by 1980 in major combustors. Notable of the AQMA which will experience shortages are Birmingham, Mobile and Savannah.

EPA Region V

EPA Region V -- Illinois, Indiana, Michigan, Minnesota, Ohio and Wisconsin -- is often characterized as the industrial heartland of the U.S. Second only to EPA Region VI in terms of industrial gas consumption, the region contains 257 MFBI with major gas combustors which account for 16 percent of gas consumption in all major combustors in the Lower 48 States. Region V combustors with capacity greater than 100 MMBtu/hr. represent 27 percent of total industrial gas consumption in the region.

MFBI gas consumption is projected to decline by 25 percent to 1980, but in varying degree in each state. In 1980, the gas shortage in major combustors is shown at 153 trillion Btu's.

Illinois, particularly the Chicago area where most of the MFBI are located, is served primarily by Natural Gas Pipeline Co. of America. The impact of significant pipeline curtailments has been largely ameliorated to date by SNG plants operated by gas distributors. After 1977, however, continued declines in pipeline supply coupled with projected residential-commercial growth is expected to result in substantial declines in boiler fuel consumption. The forecasts assume that the requirements of gas combustors, excluding boilers, without alternate fuel capabilities will be met.

Indiana is served by five different pipelines which are Panhandle Eastern, Natural Gas Pipeline Co., Texas Gas

Transmission, Midwestern, and Texas Eastern, in order of importance. No supplemental gas is projected for this state, but some residential growth is expected. For 1976 and 1977, the most significant declines are projected for the central and northern parts of the state served by Texas Gas and Panhandle. After 1977 continued declines are projected for all parts of the state.

Half of Michigan's supply is provided by Michigan-Wisconsin Pipeline, with the remainder of pipeline supply from Panhandle Eastern, Trunkline Gas Co., and Northern Natural Gas Co. The state also has indigenous production which has increased in recent years as well as SNG. In 1975 one of the two major distributors in the state received 20 percent of its supply from its SNG plant and 12 percent from intrastate production and thus was able to offset significant reductions in conventional pipeline supply. The forecasts reflect residential-commercial growth and the assumption that requirements in gas combustors without alternate fuel capabilities will be met. Thus, the decline shown is attributable to predominantly interruptible boiler fuel consumption.

Minnesota gas supply comes virtually entirely from Northern Natural Gas Company. The gas supply outlook for this company appears to confirm the GRC projection, which shows substantial residential growth and declining industrial consumption. Thus, the GRC projection has been used, except that it has been assumed that high priority industrial needs will be met out of available supply.

Wisconsin is served by Michigan-Wisconsin Pipeline Company, which imports substantial volumes of Canadian gas into the state. Residential-commercial growth is expected for the state, with the gas shortage falling entirely on interruptible industrial customers. Thus, the declines shown after 1976 are entirely attributable to boilers with alternate fuel capabilities.

Over half of Ohio's gas supply comes from Columbia Gas Transmission, with most of the remainder from Consolidated Gas Supply which serves the eastern part of the state. Both of these companies expect to import LNG beginning in 1978, which importantly affects the industrial gas supply forecast.1/ Both companies have active exploration and gas purchase programs in offshore Louisiana and have recently announced the attachment of significant new reserves. No residential-commercial growth is projected. The forecast for Ohio reflects these factors and assumes that high priority industrial gas needs will be met to the detriment of boiler fuel usage.

EPA Region VI

Region VI is by far the predominant gas consuming region in the country, encompassing the states of Texas, Louisiana, Oklahoma, Arkansas and New Mexico. The 1974 gas consumption of major MFBI combustors in 1974 was 1,549 trillion Btu's, nearly 54 percent of the Lower 48 total. Gas shortages to major MFBI combustors are projected to be 16 trillion Btu's in 1976, increasing to 131 trillion Btu's in 1980. The average yearly shortfall of 58 trillion Btu's represents 14 percent of the Lower 48 shortfall. Although the gas shortfall

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1/ The Columbia SNG plant is located in Ohio, but this gas is sold in a number of states served by Columbia.

in Region VI is projected to increase yearly, the projected consumption in 1980 is 1,549 trillion Btu's, the same as in 1974. Thus, the shortage reflects increasing demand.

The fact that Region VI is such a large gas consuming region should not automatically pose a forecasting problem. However, the vast majority of the gas consumed in Region VI is not transported across state lines, and it is therefore not subject to regulation by the Federal Power Commission. (Intrastate gas represents approximately 93 percent of the total supply in Texas, 85 percent in Louisiana, 87 percent in Oklahoma, 70 percent in New Mexico, and 12 percent in Arkansas.) As a result of the dependence on intrastate sources in Region VI, the data available pertaining to interstate gas is of little value for this region. The forecast for Region VI was based on whatever information was publicly available (annual reports to stockholders, pipeline and distribution company prospectuses, and various state collected data), and also on conversations with some state officials and industry representatives.

Texas is the largest gas consuming state in the Nation, accounting for one-third of the total Lower 48 MFBI gas consumption. Gas production in Texas has steadily declined since 1973. Total marketed production of gas for the first 10 months of 1976 was some 17 percent less than in the comparable period of 1973. However, this decline in production has had a relatively greater impact on the amount of gas sold to interstate pipelines for consumption outside the state than on the amount of Texas produced gas retained for internal consumption. Texas produced gas exported over the first 10 months of 1976 was 26 percent less than in 1973, while the portion of Texas gas retained within the state declined by only 9 percent.

Because of the declining gas production in Texas, and because of a series of intrastate curtailments in both 1973 and 1974, the Texas Railroad Commission has ordered a partial phaseout of gas consumed as a boiler fuel. In March of 1976 the Railroad Commission ordered that any gas user who consumed an average of 3,000 Mcf/d or more as a boiler fuel in 1973 or 1974 must reduce his consumption by 10 percent by January 1, 1981 and by 25 percent by January 1, 1985.

Intrastate curtailments in Texas in 1975 and 1976 were less than in 1973 and 1974, and a number of major companies indicated they were in a surplus deliverability situation. They attributed their better position primarily to sluggish gas demand, citing the effects of recession, conservation, and mild weather. The current severe winter has resulted in some intrastate curtailments, although it is not known what portion of these curtailments stem from inadequate supplies and what portion stems from pipeline capacity restraints.

The forecast for Texas utilized herein reflects a one percent decline in MFBI gas consumption as compared with a somewhat more pessimistic 8 percent decline forecast by GRC. The one percent overall decline assumes a 10 percent decline for all boiler fuel, reflecting the order of the Railroad Commission, while it is assumed that supply will meet demand for all non-boiler applications. It should be noted, however, that many of the boilers have no alternate fuel capability. Thus, it is assumed that investments in boiler modification will be made.

MFBI gas consumption in Louisiana in 1974 was 465 trillion Btu's, 16 percent of the Lower 48 total. Shortages to MFBI in Louisiana are projected to be 7 trillion Btu's in 1976 and

20 trillion Btu's in 1980. The shortfall is mainly attributable to those few MFBI served by the interstate pipelines servicing Louisiana: United Gas Pipe Line, Arkansas Louisiana, and Mid Louisiana Gas Company. It appears that only about 13 percent of the Louisiana gas consumption is linked to interstate supply sources. For MFBI served by intrastate pipelines it is assumed that gas supply will equal gas demand for any nonboiler applications for the entire period, and that boiler demand will be met until 1978, after which supply will remain constant.

No gas shortages are projected for the state of Oklahoma, which had an MFBI gas consumption of 47 trillion Btu's in 1974. The reasons for this optimism regarding the situation in Oklahoma are indicated in the following facts concerning Oklahoma Natural Gas Company, the state's major supplier: industrial gas sales increased 14 percent in 1975 and an additional 11 percent in 1976; gas reserves showed a net gain of 26 Bcf in 1976; new industrial contracts are still being accepted, including the expected sale of some 46 Bcf per year to three ammonia plants beginning in 1976; and excess gas has been available for emergency sales to interstate pipelines, as much as 36 Bcf in fiscal 1975. Although curtailments by interstate pipelines have occurred in the state, none of the major MFBI are served by these pipelines.

A relatively modest 8 trillion Btu's were consumed in 1974 in the four MFBI located in New Mexico. Three of the four MFBI are located in areas served by Southern Union Gas Company, and the GRC projection of an essentially constant supply was applied to them. The fourth MFBI, served by El Paso, is shown to have a reduction in boiler fuel consumption of approximately 25 percent per year.

Roughly 80 percent of all gas consumed in Arkansas is supplied by the Arkansas Louisiana Gas Company, an interstate pipeline company. The gas consumption by major MFBI of 40 trillion Btu's in 1974 is projected to fall to 31 trillion Btu's by 1976, and remain constant at this level through 1980. GPC also assumes a substantial reduction in industrial gas consumption at the outset of the forecast period (although slightly less than the decline used in this study), and then a relatively constant supply through the remainder of the period.

Although it is assumed that supply will equal demand in Texas through 1977, significant shortages are forecast for a number of AQMA for the period 1978 through 1980. The three year average shortage for Houston is projected at 17.3 trillion Btu's per year, while shortages for Beaumont and Corpus Christi are 15.1 and 6.3 trillion Btu's per year, respectively. The average yearly shortage in Shreveport, Louisiana is estimated at 3.6 trillion Btu's for major MFBI combustors, and a 4.2 trillion Btu per year shortage is forecast for Little Rock, Arkansas.

EPA Region VII

The major MFBI combustors in the four states of Region VII -- Kansas, Missouri, Iowa, and Nebraska -- consumed 88 trillion Btu's of gas in 1974, 3 percent of the Lower 48 total. It is estimated that consumption will fall to 66 trillion Btu's by 1980, a decline of 25 percent. This decline is quite comparable to the 27 percent decline forecast by GRC.

Most of the gas consumed in these four states is transported by interstate pipelines, although there is some intrastate production in Kansas. The primary sources of gas supply in Region VII are as follows: Iowa - Northern Natural (64 percent of total supply) and Natural Gas Pipeline (26 percent); Kansas - Cities Service Gas (48 percent), Northern Natural (13 percent), and various intrastate producers (27 percent); Missouri - Cities Service Gas (49 percent) and Mississippi River Transmission Co. (35 percent); and Nebraska - Northern Natural (61 percent) and Kansas-Nebraska Natural Gas (31 percent).

Although it is expected that consumption by customers with firm contracts will be fairly stable over the forecast period, significant cutbacks are anticipated in the interruptible industrial consumption in Region VII. The forecast assumes a 33 percent reduction in interruptible boiler consumption in Nebraska by 1980, a 35 percent reduction in Missouri, a 55 percent reduction in Iowa, and a 62 percent reduction in Kansas.

The greatest incremental shortages in Region VII are forecast for two AQMA in the Metro Kansas City AQCR. The average annual shortage forecast for Kansas City, Missouri is 2.9 trillion Btu's per year, as compared with 2.2 trillion Btu's per year for Kansas City, Kansas.

EPA Region VIII

Region VIII consists of six states: Colorado, Utah, Wyoming, Montana, North Dakota and South Dakota. The major MFBI gas combustors in these states consumed 104 trillion Btu's of gas in 1974, less than 4 percent of the Lower 48 total consumption. Gas consumption in Region VIII is forecast to decline by 16 percent to 87 trillion Btu's by 1980, as compared with a 23 percent decline forecast by GRC.

Approximately 83 percent of the 1974 MFBI gas consumption in Region VIII was accounted for by three states: Colorado (32 trillion Btu's); Utah (28 trillion Btu's); and Wyoming (27 trillion Btu's). These three states are similar in that a large portion of their gas is supplied from fields within the three state area. Two interstate pipelines supply over half of the gas consumed in these three states, Colorado Interstate and Mountain Fuel Supply, while another 25 percent of the total supply comes from intrastate sources, including Western Slope Gas Company of Colorado. The forecast utilized herein assumes a constant supply of gas to boilers in Colorado from 1976 on, and a modest decline in Utah and for most MFBI in Wyoming. A few MFBI in these states are served by other interstate pipelines, including Northern Natural and Kansas-Nebraska. The supply outlook for these MFBI is somewhat more pessimistic.

Over 56 percent of the average annual gas shortage in Region VIII (10 trillion Btu's) is accounted for by the state of Montana, even though this state's MFBI gas consumption was only 16 trillion Btu's in 1974. The primary reason for the more serious decline in Montana is that the state's major source of gas, Montana Power Company, imports about 70 percent of its gas from Canada under two long term contracts. One of the two contracts which supplied up to 20 Bcf per year expired in 1974. A limited extension was granted and 10 Bcf were imported in 1975-1976, and imports of 5 Bcf have been approved for 1976-1977. An application for an extension of the original contract volume has not been approved by the National Energy Board of Canada, and this forecast assumes that the original contract will not be renewed.

Gas consumption by major MFBI in North Dakota and South Dakota was less than 1 trillion Btu's per year in 1974, as there is only 1 MFBI in each state. South Dakota is served by two interstate pipelines, Montana-Dakota Utilities and Northern Natural, while North Dakota is served by Montana-Dakota Utilities, Midwestern Gas Transmission and various intrastate suppliers.

The only AQMA in Region VIII with an annual average shortage exceeding 2 trillion Btu's per year is Anaconda-Butte, projected at 5.6 trillion Btu's per year. Four other AQMA have annual averages projected to be in excess of 1 trillion Btu's per year: Billings, Helena, and Missoula -- all in Montana; and Sweetwater in Wyoming.

EPA Region IX

In EPA Region IX -- Arizona, Nevada and California -- there are 101 MFBI containing major gas combustors, most of which are located in California. Major combustors in this region account for 8 percent of gas consumption by all major combustors in the Lower 48 States. Of total industrial gas consumption in this region, major combustors represented 33 percent.

Arizona is served entirely by El Paso Natural Gas Company, and the forecast decline in MFBI gas consumption reflects the diminishing supply of that company. No gas is expected to be available for boiler fuel uses after 1977 and significant shortages are projected even for combustors without alternate fuel capabilities.

Nevada contains only 2 MFBI with major gas combustors, one of which is indirectly served by El Paso and the other of which is served by Northwest Pipe Line. The MFBI receiving gas from El Paso is projected to have no gas after 1977. On the other hand, the requirements of the MFBI served by Northwest -- which is projected to have increasing overall supply -- are projected to be met as the combustors do not have alternate fuel capabilities.

California is served by El Paso and Transwestern and also has indigenous production. Moreover, northern California receives substantial volumes of Canadian gas. The forecasts of both demand and supply for each MFBI were taken from the California Gas Report for 1976, which contains each distribution company's projection of gas availability by priority category. For each MFBI the priority (ies) was (were) determined according to the industrial classification, combustion process and alternate fuel capabilities.

In total, MFBI gas consumption in California is shown to decline by 43 percent between 1974 and 1980. More severe reductions are shown for southern California than northern California for two reasons. The Canadian gas used in northern California is the only source of gas not expected to decline to 1980. Secondly, substantial curtailments of electric utilities are expected in northern California as supply declines. Southern California does not have this "cushion" upon which to fall. Thus, by 1980 the gas shortage for major combustors is forecast to be 43 trillion Btu's in the South Coast AQMA, over half of the total shortage in California.

EPA Region X

In EPA Region X -- Idaho, Oregon and Washington -- there are 56 MFBI which contain major gas combustors. Major combustors in this region account for 3 percent of gas consumption by all major combustors in the Lower 48 States. Of total industrial gas consumption in this region, major combustors represented 44 percent.

Region X is supplied almost entirely by Northwest Pipe Line. Northwest in turn acquires approximately two-thirds of its gas supply from Canadian imports, with the remainder purchased in the Rocky Mountain and San Juan areas. The company experienced significant curtailments from its Canadian supplier in 1974 and 1975, which were passed on to its customers. However, Northwest estimates an increase in gas availability from reserves under contract beginning in 1976 and has obtained additional gas as well.

Thus, an overall increase in gas supply for Region X is projected. Residential-commercial consumption is expected to increase substantially, along with high priority industrial needs. The declines in consumption and shortages shown on the schedule are attributable solely to boilers with alternate fuel capabilities, and reflect the trends projected by GRC.

CHAPTER II

ALTERNATIVE FUEL USE AS A RESULT OF GAS SHORTAGES IN MAJOR MFBI GAS COMBUSTORS

Once the gas supply-demand-shortfall situation has been projected for individual MFBI, the next step in the plant by plant analysis is the determination of which fuel or fuels would be burned in order to offset any shortfall. Assuming that a plant intends to maintain operations, the substitute fuels which would be burned if the gas supply was inadequate are estimated. These estimates directly impact the calcula- tion of sulfur dioxide and particulate emissions, which may vary according to fuel type.

Methodology and Assumptions

In order to determine the alternate fuel consumption necessitated by a gas shortage, the various options available to each MFBI were analyzed. The choice of the most likely alternate fuel was then made, based on a variety of economic and technical factors. The first step in the analysis was to refer to the MFBI printout provided by FEA. The contents of this printout are more fully discussed in the appendix of this study, Volume Three. Both the primary and alternate fuels are indicated on the printout, whether they be gas, residual fuel oil, distillate fuel oil, coal or "other." No clarification is provided on the printout for primary or alternate fuels shown as "other." However, the original questionnaires from which the printout was derived were re- searched in some instances. In most cases the other fuels were consumed at crude oil refineries, steel mills, and pulp and paper mills, and included such energy sources as coke oven gas, blast furnace gas, wood chips, and black liquor. Propane was rarely specified. The term "other" is also used on the printout as a combustor type, along with boilers and burners. Other combustors generally refer to unique types of combustors such as lime kilns, open hearth furnaces, and blast furnaces.

Perhaps the easiest case for the determination of the alternate fuel consumption involves a plant with one combustor, where gas is burned as the primary fuel, and the alternate fuel is specified as residual fuel oil, distillate fuel oil, or coal. In this case a gas shortage of 50 billion Btu's in a given year would be assumed to result in a 50 billion Btu increase in the consumption of the specified alternate fuel. The result would be identical if the primary fuel was residual fuel oil, distillate fuel oil, or coal, and gas was the alternate. That is, gas is assumed to be completely interchangeable with the alternate fuel when it is the primary fuel, and completely interchangeable with the primary fuel when it is the alternate.

In a plant with more than one combustor the question is somewhat more complicated. For example, a gas-primary oil-alternate combustor might be located at an MFBI with five coal combustors which do not burn gas. There are two options available in the event of a 50 billion Btu gas shortage -- an additional 50 billion Btu's of oil could be consumed in the gas-oil combustor, or an additional 10 billion Btu's could be burned in each of the five coal combustors. It has been assumed that the former option would be exercised, that is, more oil would be burned in the gas-oil combustor. The reasons for this assumption are twofold: first, the output of the six combustors might not be interchangeable; and second, the coal combustors might already be operating at maximum capacity.

A second problem at multiple combustor plants is that gas might be consumed with different alternate fuels in different combustors. That is, a plant with a gas-coal combustor and a gas-oil combustor might increase only coal or only oil consumption in the event of a shortage. If all combustors at the MFBI were of the same type, i.e., all boilers or all burners, it was assumed that the shortage would be borne by various combustors in proportion to their 1974 gas consumption. Thus, if the gas-oil combustor consumes 75 percent of the gas it will suffer 75 percent of the shortage, and the gas-coal combustor would suffer 25 percent of the shortage.

A third complication dealt with at multiple combustor sites involves MFBI with more than one type of combustor. For example, an MFBI may have two combustors, one boiler and one burner (or other), both of which consumed 100 billion Btu's of gas in 1974. In the event of a 50 billion Btu gas shortage, each combustor could consume an additional 25 billion Btu's provided by alternate fuels, or the boiler could bear the brunt of the entire shortage. In cases such as this it was assumed that the entire shortage would be borne by the boiler. There are a variety of factors which influenced this assumption. As discussed in Chapter III of this study, the emissions of boilers are subject to combustion regulations. Burners and others, however, may be governed by process regulations which tend to be more strict than combustion regulations.

In general, the allowable rate of emission from a boiler is directly proportional to its heat input. Allowable emissions from burners and others may be governed primarily by the input weight of process weight and tend to be more strict. Thus, the rational choice of a profit maximizing firm would be to cut back only the gas supply of the boiler. This decision would result in the dirtier alternate fuel being burned in the boiler with the more lenient emission regulations, and thus pollution control costs and fuel purchase costs would be minimized. Secondly, there may be an incentive to restrict the shortage to the boiler in order to insure process quality in the burners (or others). Finally, burners and others may be more susceptible than boilers to damages cause by the impurities contained in coal and oil. The cost of maintaining equipment might therefore be lower if the incremental alternate fuel consumption was restricted to boilers when possible.

In some instances the primary fuel is listed as gas on the MFBI printout, and no alternate fuel is indicated. Plants lacking the capability to substitute an alternate fuel for gas might reduce operations if faced with a shortage, or they might even temporarily shut down. (In fact, a number of plant shutdowns resulting from gas shortages have been reported this winter, reflecting the extremely cold weather.) For purposes herein, it was assumed that all gas shortages could be offset by the utilization of an alternate fuel. Since this study covers a five-year period on an annual basis, the short-run or temporary relief measures undertaken at gas-short MFBI may differ from the expected long-run strategies. For example, unexpected spot interruptions of gas service on peak winter demand days might be met with a substitution of propane. A long term interruption, however, might be more likely to result in an increased usage of less expensive residual fuel oil. Further, propane might be used during the modification of a combustor to some other fuel. It is also possible that a temporary plant shutdown could be a more economically feasible short-run option than a major plant conversion. Various assumptions involving the "no alternate" case are set out below.

In some cases, even though a combustor is shown as having no alternate fuel capability, some quantities of oil or coal were consumed in 1973 or 1974. In such cases, these other fuels were considered to be a viable alternate to gas. Further, if there are other combustors at the plant which appear to be operating below maximum capacity and which appear to have an interchangeable output with the gas combustor, it was assumed that the output and primary fuel consumption of these other combustors would increase to offset the decline in the gas combustor. Even if the remaining combustors at the plant are not interchangeable with the gas combustor they might represent a potential means to minimize the effects of a gas shortage. For example, a plant might have five coal-gas combustors used to produce process steam and one gas combustor with no alternate fuel used to generate electricity. It is assumed that in the event of a shortage gas would be taken from the coal-gas units and allocated to the gas only unit in order to keep it in operation. Thus, the gas shortage would result in an increase in coal consumption even though the combustor under consideration has no reported alternate fuel.

A few coal combustors are listed as having no alternate fuel capability, and yet some minor amounts of gas were consumed in 1973 and 1974; e.g., one percent of total combustor consumption. It was assumed that this gas is used either as a starter fuel or for flame stabilization purposes. It was further assumed that the only alternate to this gas would be propane, unless some minor quantity of fuel oil was also consumed. In any cases where no alternate to gas was indicated, and where the above discussed approaches were inappropriate, the most likely alternate to gas was used (including propane).

In some cases, gas is the alternate fuel and the primary fuel is shown as "other." The "other" primary fuel may be coke oven or blast furnace gas at steel mills, refinery gas at crude oil refineries, or wood at pulp and paper mills. In general, these "other" types of fuel are plant by-products and may be consumed at little or no expense. It was therefore assumed that these plants already use as much of the "other" fuel as is available, and gas is consumed as a supplemental fuel. Thus, these combustors could not burn more "other" in the event of a gas shortage. The procedure for the determination of the applicable alternate in these cases was therefore similar to the gas-no alternate case; i.e., reference was made to other combustors at the plant, and to any other fuels which may have been consumed in the gas-"other" unit. If these approaches were not feasible, a "most likely" alternate was chosen.

Projected Alternative Fuel Use by AQCR and AQMA

Schedule II-1 sets out the projected alternative fuel use as a result of gas shortages in major MFBI gas combustors by AQCR and AQMA from 1976 through 1980 in billions of Btu's per year. It should be noted that the increases in alternate fuel consumption indicated on Schedule II-1 are identical in quantity to the gas shortage projections of Schedule I-2 for corresponding geographic areas.

The increase in alternative fuel consumption for the Lower 48 States is projected at 203 trillion Btu's in 1976, increasing to 612 trillion Btu's in 1980. The average annual increase of 408 trillion Btu's is distributed by fuel type as follows: residual fuel oil = 251 trillion Btu's (61.4 percent); distillate fuel oil = 104 trillion Btu's (25.5 percent); coal = 51 trillion Btu's (12.5 percent); and "other" = 2 trillion Btu's (0.6 percent).

The incremental increase in residual fuel oil consumption projected for these major MFBI gas combustors in 1980 is 357 trillion Btu's, approximately 17 percent of the Lower 48 total industrial residual fuel oil consumption in 1974. The comparable figures relating distillate fuel oil and coal to the 1974 industrial totals are 39 percent and 5 percent, respectively. A summary of the results by EPA region follows.

Total fossil fuel consumption of all major MFBI combustors in Region I in 1974 was 110 trillion Btu's. Of this amount over 93 percent was supplied by residual fuel oil, and only 5 percent by gas. As might be anticipated, virtually all shortages in Region I are expected to be offset by increased residual fuel oil consumption. The gas shortage for major combustors in Region I is projected to increase from a modest level of 1.4 trillion Btu's in 1976 to 2.4 trillion Btu's in 1980; 99 percent of this amount to be replaced by residual fuel oil and 1 percent by distillate fuel oil. Most of the increased alternate fuel consumption is shown to occur in Massachusetts (1.1 trillion Btu's in 1976, 1.9 trillion Btu's in 1980), with approximately 50 percent of the state total attributable to the Boston AQMA.

Major combustors in Region II are similar to those in Region I in that most energy is derived from residual fuel oil. Some 21 trillion Btu's were supplied by gas in 1974, about 9 percent of the region's total fossil fuel consumption, by all major MFBI combustors. The gas shortage in Region II is projected to be 4.4 trillion Btu's in 1976, increasing to 5.4 trillion Btu's in 1980. The impact of the gas shortage will be lessened somewhat in Region II due to expected increases in supplemental gas in the form of LNG. The 4.4 trillion Btu shortage in 1976 will be met by an increase in residual fuel oil consumption of 4.2 trillion Btu's -- 3.0 trillion Btu's in New Jersey and 1.2 trillion Btu's in

New York. Most alternate fuel consumption is projected to occur in the New Jersey portion of the New York-New Jersey AQMA.

Natural gas supplied 92 trillion Btu's of the 753 trillion Btu's consumed by all major MFBI combustors in Region III in 1974, roughly 12 percent of the regional total. The gas shortage in Region III is projected to average 27 trillion Btu's per year over the five-year forecast period. In order to offset this shortage an additional 18 trillion Btu's per year of residual fuel oil will have to be burned, as well as 7 trillion Btu's per year of distillate fuel oil and 2 trillion Btu's per year of coal. Pennsylvania is expected to account for 49 percent of the projected increase in alternate fuel consumption, including some 9 trillion Btu's per year of residual fuel oil, 3 trillion Btu's per year of distillate fuel oil, and 1 trillion Btu's per year of coal. Most of the increases in Pennsylvania are shown to occur in the Metropolitan Philadelphia and Southwest Pennsylvania AQCR. Alternate fuel consumption is projected to exceed 2 trillion Btu's per year in four of the Region III AQMA: Baltimore and Potomac River, Maryland; Metro Philadelphia, Pennsylvania; and Petersburg-Colonial Heights-Hopewell, Virginia.

The alternate fuel consumption in Region IV resulting from gas shortages is projected to average 99 trillion Btu's over the five-year period. This shortage is projected to be met by an increase in residual fuel oil consumption of 66 trillion Btu's per year, along with 20 trillion Btu's per year of distillate fuel oil and 13 trillion Btu's per year of coal. Nearly 30 percent of the additional oil consumption is in the Mobile-Pensacola-Panama City-Southern Mississippi AQCR, while most of the coal increases are scattered throughout the region. The three AQMA with the largest expected annual increases in alternate fuel consumption are: Mobile, Alabama (5.7 trillion Btu's per year of residual fuel oil); Birmingham, Alabama (4.6 trillion Btu's per year of coal and 1.2 trillion Btu's per year of residual fuel oil); and Savannah, Georgia (3.4 trillion Btu's per year of residual fuel oil). Two AQCR in Tennessee are shown to have increases in alternate fuel consumption of approximately 10 trillion Btu's per year each: Metro Memphis (fuel oil) and East Tennessee (both fuel oil and coal).

The projected increases in alternate fuel consumption are larger in Region V than in any other region, some 3 percent greater than those projected for Region IV. The average annual increase of 102 trillion Btu's is distributed as follows: residual fuel oil = 59 trillion Btu's per year; distillate fuel oil = 18 trillion Btu's per year; coal = 24 trillion Btu's per year; and "other" = 1 trillion Btu's per year.

The incremental increase in coal consumption is relatively high in Region V, accounting for 24 percent of the region's total increase in alternate fuel use, and 47 percent of the average annual coal increase for the Lower 48 States. Nearly 70 percent of the coal increase is attributable to 2 AQMA: Illinois-Indiana-Wisconsin (9.0 trillion Btu's per year) and Detroit (7.3 trillion Btu's per year). On the other hand, over 50 percent of the region's increased fuel oil consumption is projected to occur in 3 AQMA: Illinois-Indiana-Wisconsin (19.4 trillion Btu's); Cincinnati (11.1 trillion Btu's); and Detroit (8.5 trillion Btu's).

Gas consumption by all major MFBI combustors in Region VI in 1974 was 1,549.5 trillion Btu's, 92 percent of their total fossil fuel consumption. These combustors thus accounted for 54 percent of the Lower 48 total gas consumption, but are projected to account for only 14 percent of the average annual increase in alternate fuel consumption (58.4 trillion Btu's). A number of gas combustors in Region VI do not have alternate fuel capabilities, and thus it has been assumed that combustor modification will take place as the need arises. The distribution of the increases by fuel type in Region VI indicates almost an even split between distillate and residual fuel oil, 27.7 trillion Btu's vs. 30.7 trillion Btu's while no increases in coal consumption are projected for these combustors. Distillate accounts for 47 percent of the increase in fuel oils, noticeably higher than the 26 percent share in the remaining 9 regions. The amount of combustor modification is less for the lighter oils.

Two AQMA in Region VI located outside of Texas, Little Rock and Shreveport, have projected average annual increases in fuel oil consumption of 4.2 trillion Btu's and 3.6 trillion Btu's, respectively. No increases are projected for the state of Oklahoma, due to the optimistic intrastate supply picture in that state, nor are any increases projected for Texas in 1976 or 1977. The average annual increase in fuel oil consumption (based on three years) for four major AQMA in Texas is set out as: Houston - 17.3 trillion Btu's; Beaumont - 15.1 trillion Btu's; Corpus Christi - 6.3 trillion Btu's; and Galveston - 3.4 trillion Btu's.

The annual increase in alternate fuel consumption is projected to average 21.2 trillion Btu's per year in Region VII, approximately 5 percent of the Lower 48 total. The portion of the total increase accounted for by coal is high in Region VII relative to the other nine regions, 33 percent vs. 11 percent. Four trillion Btu's of the 7 trillion Btu per year increase in coal consumption are projected for

Iowa. The AQMA in Region VII with the greatest annual increase in alternate fuel consumption is Kansas City, averaging 4.5 trillion Btu's in residual fuel oil consumption and 0.6 trillion Btu's in coal consumption.

The total fossil fuel consumption of all major MFBI combustors in Region VIII in 1974 was 212 trillion Btu's. Of this total, roughly one half was supplied by gas. The average annual increase in alternate fuel consumption resulting from gas shortages is estimated at 17.4 trillion Btu's -- 8.7 trillion Btu's from residual fuel oil, 7.7 trillion Btu's from distillate fuel oil, and 1.0 trillion Btu's from coal. The incremental alternate fuel consumption is relatively small in all states, except Montana, for two primary reasons: some states have very few MFBI (North Dakota and South Dakota) and the intrastate gas supply outlook is fairly good in some states (Colorado, Utah, Wyoming).

The increase in alternate fuel consumption in Montana accounts for over 55 percent of the Region VIII total, averaging nearly 10 trillion Btu's per year. The fundamental reason for the situation in Montana is that imports of Canadian gas to the state's primary utility are rapidly declining due to the termination of a major contract. AQMA in Montana with average annual alternate fuel increases exceeding 1 trillion Btu's per year include: Anaconda-Butte (5.6 trillion Btu's, distillate fuel oil); Helena (1.5 trillion Btu's per year, residual fuel oil); Billings (1.3 trillion Btu's per year, residual fuel oil); and Missoula (1.0 trillion Btu's per year, residual fuel oil). It might seem surprising that no increases in coal consumption are projected for Montana. It should be remembered, however, that the instant report deals only with a specific set of large gas burning combustors, not the entire industrial sector of the state.

Over 80 percent of the total energy consumption of all major MFBI combustors in Region IX in 1974, or 215.8 trillion Btu's was supplied by natural gas. The increases in alternate fuel consumption projected for this region average 68.0 trillion Btu's per year -- 54.1 trillion Btu's attributable to California, 13.7 trillion Btu's attributable to Arizona, and less than 1 trillion Btu's attributable to Nevada. Fuel oil, the overwhelming choice as a substitute fuel in Region IX, is shown to alleviate 64.4 of the 68.0 trillion Btu shortfall.

The incremental use of alternate fuels to offset gas shortages is projected to be greater for California than any other state in the Lower 48. Since most large industrial gas users in California purchase gas on an interruptible basis, many plants can accommodate both gas and fuel oil (coal is usually not a viable alternative due to the relatively stringent air pollution regulations in California and the traditional availability of gas and oil). The state's average annual increase in alternate fuel consumption is largely attributable to 3 AQMA: South Coast (17.3 trillion Btu's of residual fuel oil and 9.5 trillion Btu's of distillate fuel oil); Southeast Desert (8.0 trillion Btu's per year of residual fuel oil); and San Francisco Bay (4.8 trillion Btu's per year of residual fuel oil and 1.3 trillion Btu's of distillate fuel oil).

The increase in alternate fuel consumption in Region X is relatively small, exceeding only the increases in Regions I and II. The average annual increase in Region X is estimated at 7.9 trillion Btu's per year (all from fuel oil), as compared with the total major combustor gas consumption in 1974 of 85.4 trillion Btu's. Over 90 percent of the average annual increase is accounted for by the state of Washington, included in which are the following AQMA: Puget Sound (3.7 trillion Btu's per year increase), and Portland-Vancouver (0.9 trillion Btu's per year increase).

CHAPTER III

PROJECTION OF INCREMENTAL EMISSIONS OF SULFUR DIOXIDE AND PARTICULATE MATTER RESULTING FROM SHORTAGES OF GAS IN MAJOR MFBI GAS COMBUSTORS

The end results of this study, as discussed in this chapter, are the projected emissions of sulfur dioxide and particulates resulting from alternate fuel use. Natural gas is the cleanest burning of fossil fuels, generally containing negligible amounts of sulfur and ash as compared to coal or oil. Hence, the use of alternate fuels to replace dwindling gas supplies will result in additional emissions of air pollutants.

First this chapter sets out the general assumptions and overall methodology used to determine the incremental emissions of sulfur dioxide and particulate matter resulting from shortages of gas in major MFBI gas combustors. Then the results by area as well as specific state and local air quality regions are discussed.

General Assumptions and Data Used to Determine Emissions

This study determines the increase in emissions attributable to alternate fuel use by major MFBI gas combustors. More specifically, the projected emissions reflect the maximum allowable increase subject to the constraints imposed by the individual State Implementation Plans (SIP's). The emissions resulting from alternate fuel use are, to a large degree, dependent upon the physical characteristics of the fuel consumed and the availability and capabilities of control equipment. Therefore, it is possible that the incremental emissions associated with alternate fuel use could be less than the maximum allowable. However, due to the generally greater costs associated with higher quality fuels and control equipment, it was assumed the MFBI would be operated at the maximum allowable rate of emissions. (Of course, it is also possible that some sources may not be in compliance with EPA standards, and thus an estimation based on a maximum allowable level could understate actual emissions.)

The primary reference source of the sulfur oxide regulations used in the calculation of emissions in this report is State Implementation Plan Emission Regulations for Sulfur Oxide: Fuel Combustion.[1] A similar publication, State Implementation Plans for Particulate Matter: Fuel Combustion,[2] provided most of the data used in the calculation of particulate emissions. These reports contain a summary of each state's implementation plan for the control of sulfur oxides and particulate matter as interpreted by EPA's Strategies and Air Standards Division.

Moreover, Mr. Rayburn Morrison of the EPA's Energy Strategies Branch and Mr. C. H. Kuo were consulted during the preparation of this study in order to identify any recent changes in the status of the state emissions regulations and to provide assistance in the formulation of assumptions and guidelines required for the calculation of incremental emissions.

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[1] U.S. Environmental Protection Agency, State Implementation Plan Emissions Regulations for Sulfur Oxides: Fuel Combustion, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, March 1976, (EPA-450/2-76-002).

[2] U.S. Environmental Protection Agency, State Implementation Plans Emissions Regulations for Particulate Matter: Fuel Combustion, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, August 1976, (EPA-450/2-76-010).

Regulations reported in the above documents are primarily applicable to fuel combustion equipment. Although the definition of fuel combustion equipment may vary from state to state, these regulations generally apply to steam-electric generating plants and industrial boilers which burn fuel to generate power and steam (i.e., indirect heat transfer applications).

Fuel combustion regulations are not applicable to many industrial processes utilizing direct heat exchangers in which products of fuel combustion come in direct contact with process materials. Examples of these industrial processes include steel production, cement and lime production, and driers used in the agricultural processing industry. In such cases, process regulations are applicable.

Calculations of the emissions from these industrial processes were based upon the process regulations presented in *The World's Air Quality Management Standards*.[1] This publication is a compilation of the applicable process regulations for both sulfur dioxide and particulate matter emissions by state and also by county or city, where such local regulations exist. Other sources used were the State Air Laws published in the Bureau of National Affairs, Inc., Environmental Reporter, and the State Implementation Plan files maintained by the Office of Air Quality Planning and Standards. Only those local regulations which are part of the state implementation plans were included in the emissions calculations.

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[1] U.S. Environmental Protection Agency, *The World's Air Quality Management Standards, Volume II: The Air Quality Management Standards of the United States*, Office of Research and Development, October 1976, (EPA-650/9-75-001-b).

In order to determine which emissions regulations were applicable, combustion regulations or process regulations, certain assumptions were required in classifying the MFBI data. All combustors classified as boilers in the MFBI data were considered to be subject to the fuel combustion regulations, since this is an indirect heat transfer application. Additionally, it was assumed that any combustor with more than 50 percent of its output classified as electrical generation or process steam was used primarily for indirect heat transfer and therefore was also subject to combustion regulations. The remaining combustors were further evaluated with respect to the plant operations as identified by the SIC code reported in the questionnaire. In some instances, the plants reported specific applications of these combustors in the MFBI data. If the specific application was not reported, a determination of the "most likely" application was made, based upon the general technology and requirements of the associated industry. The combustor application was then used to determine whether the combustion or process regulations were applicable.

Process regulations are somewhat more complex than combustion regulations since most state process regulations are specified as a functional relationship with the maximum allowable emissions being a function of some combustor variable. In most cases, the most important variable determining the allowable rate of emission is rate of change of process material and solid fuels to a combustion facility (commonly known as charging rate, c, or process weight per unit time, p) expressed in pounds per hour or tons per hour. Such variables were not contained in the MFBI data, but in some cases they were provided by the EPA. When the necessary information was not available an estimate of incremental emissions was calculated based on the average sulfur content of the fuel and/or emissions factors as discussed in a subsequent section.

It was sometimes necessary to distinguish between new and existing combustors in order to determine the applicable regulation. Combustors constructed or subjected to major modifications after the formal proposal of new source regulations by individual states must comply with the new source state regulations (in addition to the Federal new source performance standards). Since the date the combustor was designed or ordered may qualify as the date of construction, and due to the long lead times required for combustor installation, almost all combustors reported as operating in 1974 in the MFBI data are exempt from the state new source regulations. It was assumed that a one year lead time was required for the installation of an oil or gas burning combustor with a design firing rate of 250 million Btu's per hour or less. Oil or gas burning combustors with a design firing rate greater than 250 million Btu's per hour and all coal-fired combustors were assumed to require a two year lead time for installation.

Several state emissions regulations, for both sulfur dioxide and particulate matter, also include an excess air factor (X) in the determination of allowable emissions. Some state regulations specify the excess air factor, usually at 50 percent. When the excess air was not specified by the regulation it was assumed that the excess air was 10 percent for oil-fired combustors and 10 percent for coal-fired combustors.

Calculation of Sulfur Dioxide Emissions

State regulations enacted to control ambient air concentrations of sulfur dioxide (SO_2) may limit either the sulfur content of fuel or the emission of sulfur dioxide. The units specified in state regulations vary among the states and include: percent sulfur of fuel, pounds of SO_2 per million Btu, pounds sulfur per million Btu, parts per million SO_2 in exhaust gas, pounds SO_2 per hour, and impact on ambient air quality in parts per million. With the exception of regulations stated in terms of the impact on ambient air quality, the emission limitations were converted to equivalent units of pounds of SO_2 per million Btu, using appropriate conversion factors.

Where states had implementation plans that specified no sulfur emission limits or specified emissions limitations in terms of the impact on ambient air quality, an estimate of the increase in emissions resulting from alternate fuel use was developed based upon the sulfur and heat content of fuels burned in the geographical area in which the MFBI was located. For example, if an MFBI reported residual fuel oil as an alternate fuel, the average sulfur content and the average heat content of residual fuel oil consumed in the area were determined. It was then assumed that the MFBI would burn this same type of residual fuel oil. The ratio of sulfur content to heat content provided an estimate of pounds of sulfur dioxide per million Btu's emitted if the fuel were used as an alternate.

Allowable sulfur dioxide emission rates as enacted by the states may apply to (1) the entire plant, (2) an individual combustor, or (3) an individual stack. In this study, emissions were calculated on a combustor by combustor basis.

Each combustor was assumed to remain in compliance with the applicable regulation. Therefore, this procedure effectively insured compliance for individual stacks and the entire plant. An alternative, and more complex, method of emission calculations for regulations applicable to the entire plant (or individual stacks) would be to assume some combustors would exceed the plant regulation while some combustors would operate significantly below the regulation as long as the average emissions did not exceed the plant limitation. However, due to data limitations this alternative was not feasible.

Some states have sulfur dioxide regulations which are a function of a given industrial plant operating variable. For example, in Minnesota the sulfur dioxide emission rate is expressed as a function of the heat input rate to the entire plant. Such regulations, therefore, require an estimate of heat input rates. In these instances it was assumed the average industrial plant combustors operated at 90 percent of installed capacity. Therefore, Q, the heat input rate, was assumed to be 90 percent of the total design firing rate (TDFR) for the entire plant. In other words, when the plant was operating, it was assumed to operate at a rate which was 90 percent of its design firing rate. Similarly, when Q was defined as the heat input for an individual stack, the applicable Q was determined as 90 percent of the installed firing rate of major combustors associated with a given stack.

The calculation of the incremental increase in sulfur dioxide emissions attributed to the gas shortfall involved multiplying the sulfur emissions regulation or limitation (lbs. of SO_2/MMBtu) by the Btu equivalent of the required alternate fuel (MMBtu/yr.). This resulted in an estimate, stated in thousands of pounds per year, of the increase in emissions from the alternate fuel.

Calculation of Particulate Matter Emissions

State regulations for allowable particulate emissions, like the sulfur dioxide regulation, are expressed in various units of measurements. These include: pounds of particulate per million Btu, pounds of particulate per hour, pounds of particulate per thousand pounds of stack gas, grains per standard cubic foot (SCF), and grains per standard cubic foot, dry basis (SCFD). To facilitate the necessary calculations, all regulations were converted to equivalent pounds of particulate matter per million Btu.

Many state particulate matter regulations are a function of the heat input value, Q. The applicable emission limitation must be calculated in the same manner as the sulfur dioxide regulation for Minnesota as previously noted. Generally, the heat input value (Q), expressed in MMBtu/hr., pertains to (1) the aggregate heat content of all fuels burned, (2) maximum design heat input, or (3) the maximum of (1) and (2). If the regulation specified Q as the aggregate heat content of all fuels burned at a plant, it was estimated at 90 percent of the plant's total design firing rate (TDFR). When Q was specified as the maximum design heat input, it was estimated at 100 percent of the TDFR.

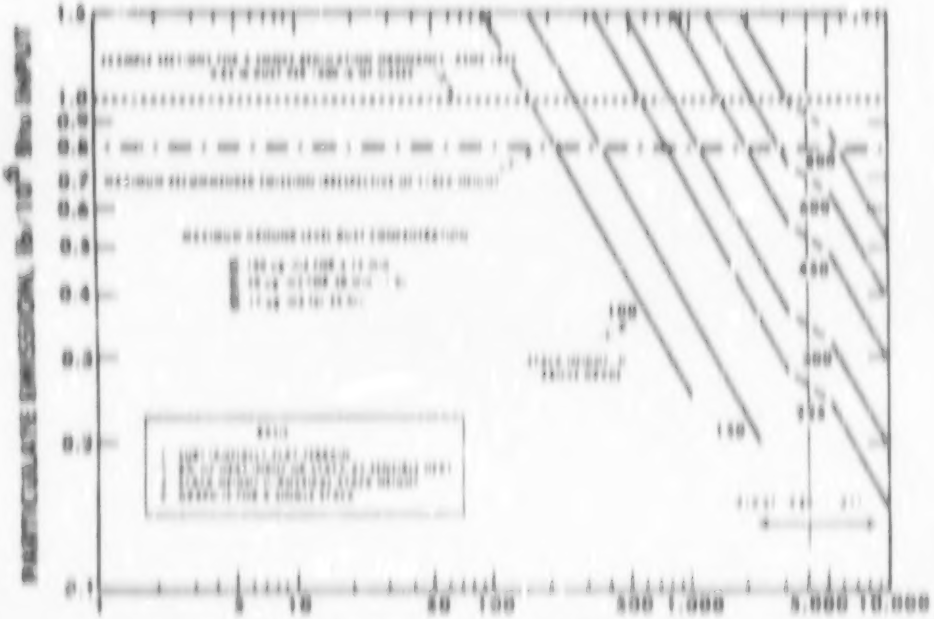
Additionally, the heat input value in some cases pertains to individual combustors or individual stacks. In these cases the relevant factor, either 90 percent or 100 percent, was applied to the reported design firing rate of the individual combustors or to the total reported design firing rate of the major combustors associated with a given stack.

Other types of particulate matter limitations frequently encountered in the state regulations specify a fixed maximum allowable rate, such as 0.1 pounds per million Btu, or a limitation based upon ASME Standard APS-1, with a specified maximum allowable rate. With the ASME Standard APS-1 (reproduced here on the following page) the allowable emissions are a function of the combustor capacity rating in million Btu per hour and the associated stack height. The applicable regulation would then be the minimum of the value obtained from the graph or the maximum allowable rate.

It should also be noted that when the ASME Standard APS-1 was specified as the relevant state particulate emissions regulation, the emissions limitation could vary from stack to stack, depending upon the individual stack heights. (There would be no variation in a state such as Minnesota where the total equipment capacity refers to the entire plant, but there could be a variation in a state such as Wisconsin where equipment capacity refers to individual stacks.) The method of allocating alternate fuels among the different stacks could produce different estimates of emissions. As discussed in Chapter II, when all combustors at an MFBI were classified as indirect heat applications, the consumption of alternate fuels due to the gas shortfall was apportioned to the individual combustors or stacks in proportion to the 1974 gas consumption of the units. Therefore, the weighted average allowable

ASME STANDARD, APS-1, FIGURE 2

PARTICULATE EMISSION, FUEL BURNING OPERATIONS



TOTAL EQUIPMENT CAPACITY RATING, 10^6 Btu/hr INPUT emissions limitation for the total MFBI was constant throughout the forecast period.

However, when the MFBI contained combustors used for direct and indirect applications, it was assumed the MFBI would be operated in a manner to protect the gas requirements of the direct applications, thereby allocating the shortfall to the indirect applications. In this case, the emissions limitation would be that regulation applicable to the combustors used in indirect applications. The emissions regulations associated with the direct applications did not enter into the calculations until all the gas was displaced from the indirect applications and the direct applications required alternate fuel. When this occurred, the weighted average allowable emissions limitation for the total MFBI changed from year to year to reflect the emissions limitations on the use of alternate fuel in the indirect applications plus the emissions limitation associated with the increasing use of alternate fuel in the direct applications.

Several states have no limitation on particulate emissions or have regulations expressed in terms of the impact on ambient air quality. In these cases the incremental emissions were calculated through the use of emissions factors. These emissions factors are representative estimates of the particulate matter emitted when fuels are burned in uncontrolled industrial combustors.[1] Representative calculations for distillate fuel oil, residual fuel oil, and bituminous coal are set out below.

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[1] U.S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, Second Edition, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, February 1976 (AP42).

Estimated Particulate Matter Emitted by Uncontrolled Industrial Combustors

Fuel	Particulate Emissions (#/MMBtu)
Distillate Fuel Oil (@ 139,000 Btu/gal.)	0.11
Residual Fuel Oil (@ 150,000 Btu/gal.)	0.15
Bituminous Coal (@ 10% ash, 12,000 Btu/lb.)	10.00

For some combustors, used in direct heat transfer applications, no incremental increase in particulate emissions was calculated since the available data indicated these combustors were most likely not in compliance with the applicable particulate regulations. This non-compliance is associated primarily with particulate matter emitted from industrial processes other than fuel combustion. For these types of processes the emissions from fuel combustion generally constitute a negligible fraction of the total emissions from the process. Since the allowable level of emissions in these processes was most likely exceeded, no incremental increase in allowable emissions was possible. Examples of the applications for which no increase in allowable emissions were calculated are: cement and lime kilns, driers used in food processing and industrial inorganic chemicals, asphalt batch plants, and sintering plants in the steel industry.

After all relevant state emissions regulations were identified and converted to an equivalent pounds per million Btu basis, the incremental increase in emissions attributed to the use of alternate fuel was calculated by multiplying the particulate emissions limitation (lbs./MMBtu) by the energy equivalent of the alternate fuel that would replace gas consumption (MMBtu/yr.). This calculation yielded the estimated increase in allowable particulate emissions in thousands of pounds per year.

Summary of Estimated Incremental Emissions

The incremental emissions of both sulfur dioxide and particulates are set out by EPA Region, state, AQCR and AQMA for the period 1976 through 1980 at Schedule III-1. The increase in sulfur dioxide emissions due to the gas shortage for the Lower 48 States is estimated at 214 thousand tons in 1976, increasing to 509 thousand tons in 1980. The average annual increase is 370 thousand tons, of which 40 percent is attributable to Region IV and 20 percent is attributable to Region V.

The major gas combustors at the 1087 MFBI are also projected to emit an additional 48 thousand tons per year of particulate matter, 22 thousand tons in 1976 and 71 thousand tons in 1980. Region V accounts for over 23 percent of the average annual increase in particulates, while Regions IV and IX account for 22 and 23 percent, respectively.

The incremental emissions of sulfur dioxide in EPA Region I are estimated at 637 tons in 1976 and are projected to increase to 1,412 tons in 1980. Approximately 90 percent of the total sulfur dioxide emissions in Region I over the five year period are attributable to MFBI located in Massachusetts, while the remainder is attributable to MFBI located in Connecticut. The projected emissions increases are most concentrated in the Boston AQMA, which accounts for more than one-half of EPA Region I emissions.

The incremental emissions of particulates in Region I are projected to increase from 93 tons in 1976 to 165 tons in 1980. Massachusetts and Connecticut produce all the projected incremental emissions. More than one-third of the incremental particulate emissions is attributable to the Boston AQMA.

In Region II, the incremental sulfur dioxide emissions are projected to be 932 tons in 1976 and 987 tons in 1980. The largest incremental increase in Region II is projected for 1977, when the increase is estimated at 1,093 tons. The New Jersey-New York AQMA emissions account for approximately two-thirds of the region total in 1976 and more than three-fourths in 1980. Within the New Jersey-New York AQMA, the New Jersey portion accounts for approximately 70 percent of the increase in sulfur dioxide emissions in 1976 and more than 82 percent in 1980. The Niagara Frontier AQMA accounts for approximately 20 percent of the Region II emissions in 1976 but its share declines to about 10 percent in 1980.

The incremental particulate emissions in Region II are projected to increase from 227 tons in 1976 to 289 tons in 1980. The New Jersey-New York AQMA accounts for approximately 80 percent of the Region II total. Within the New Jersey-New York AQMA, approximately 77 percent of the incremental increase is attributed to the New Jersey portion in 1976, while in 1980 the New Jersey share is estimated at 87 percent. The portion of the incremental particulate emissions in Region II attributed to the Niagara Frontier AQMA declines from approximately 10 percent in 1976 to 3 percent in 1980.

In Region III, the projected incremental emissions of sulfur dioxide amount to 16,701 tons in 1976 and gradually increase to 21,914 tons in 1980. Pennsylvania accounts for approximately 36 percent of the emissions and Virginia accounts for about 44 percent over the forecast period. Four

AQMA account for almost one-third of the projected increases in emissions. These are the Petersburg-Colonial Heights-Hopewell and the Lynchburg AQMA in Virginia, and the Potomac River and Baltimore AQMA in Maryland.

The incremental particulate emissions in Region III are projected to be 1,588 tons in 1976 and are expected to increase to 2,402 tons in 1980. More than one-half of the increase is attributable to Pennsylvania and about one-fourth is attributable to Virginia. Three AQMA, each with projected emissions greater than 100 tons in 1976, account for approximately 42 percent of the incremental increase in particulate emissions in Region III. These are the Potomac River AQMA in Maryland, the Metro Philadelphia AQMA in Pennsylvania, and the Petersburg-Colonial Heights-Hopewell AQMA in Virginia.

In Region IV, the incremental emissions of sulfur dioxide are projected to increase from 101,352 tons in 1976 to 190,053 tons in 1980. The two states with the largest projected increases are Tennessee and Alabama. During the forecast period, these states account for more than 45 percent of the regional total. Seven AQMA in Region IV are projected to have incremental emissions greater than 1,000 tons in 1976. These AQMA are: Gadsden, Birmingham and Mobile in Alabama; Lakeland-Winterhaven in Florida; Savannah in Georgia; and Chattanooga and Nashville in Tennessee.

The incremental particulate emissions in Region IV are projected to increase from 7,280 tons in 1976 to 13,216 tons in 1980. Tennessee and North Carolina account for more than 50 percent of the increase in 1976. Five AQMA -- Birmingham, Mobile, Savannah, Chattanooga and Nashville -- are projected to have incremental emissions greater than 100 tons in 1976.

In the calculation of both particulate and sulfur dioxide emissions for Florida, it was assumed that all MFBI are subject to the regulation pertaining to MFBI consuming more than 250 MMBtu/hr. The Florida implementation plan requires that sources consuming less than 250 MMBtu/hr. must use the "latest reasonable available technology" in emissions control.

In Region V, the incremental emissions of sulfur dioxide are projected to increase from 34,144 tons in 1976 to 105,333 tons in 1980. In 1976, Ohio accounts for more than 50 percent of the increase. In 1980, Ohio's share declines to about 20 percent of the total, while Illinois and Indiana each account for about 25 percent of the total. Six AQMA in Region V are projected to have emissions greater than 1,000 tons in 1976. These are the Illinois and Indiana portions of the Illinois-Indiana-Wisconsin AQMA, Detroit, Cincinnati, Toledo, Akron-Canton, and Columbus. By 1980, the Illinois and Indiana portions of the Illinois-Indiana-Wisconsin AQMA and Detroit are projected to have emissions in excess of 10,000 tons each and will account for more than 30 percent of the total Region V incremental emissions of sulfur dioxide. (The sulfur SIP for Ohio promulgated by EPA on August 27, 1976 is currently being challenged in the courts.)

The incremental emissions of particulates in Region V are projected to increase from 4,255 tons in 1976 to 16,715 tons in 1980. Michigan and Ohio account for 67 percent of the incremental emissions in 1976. Five AQMA -- Detroit, Minneapolis-St. Paul, Cincinnati, Toledo, and the Indiana portion of the Illinois-Indiana-Wisconsin AQMA -- are projected to have incremental increases greater than 100 tons in 1976.

The Illinois projection assumes there are no "controlled" sources as defined in the state's implementation plan. All coal used as an alternate fuel in Michigan was assumed to be pulverized coal and therefore subject to a stricter regulation.

Region VI incremental emissions of sulfur dioxide are projected to increase from 19,289 tons in 1976 to 70,352 tons in 1980. The majority of the increase is attributed to Louisiana, which accounts for 63 percent of the Region VI total in 1976 and 53 percent in 1980. No incremental increase in emissions is attributed to Oklahoma during the forecast period and no increase is projected for Texas until 1978. Emissions projected for the Shreveport, Louisiana AQMA are almost 8,000 tons in 1980. In addition, the Little Rock, Corpus Christi and Houston AQMA are projected to have emissions in excess of 4,000 tons in 1980.

Incremental particulate emissions in Region VI are estimated at 2,232 tons in 1976 and are projected to increase to 11,892 tons in 1980. Louisiana's share of the increase amounts to 88 percent in 1976 and 50 percent in 1980. By 1980 the Shreveport, Beaumont and Houston AQMA are projected to have incremental particulate emissions in excess of 1,000 tons.

In Region VII, incremental sulfur dioxide emissions are projected to increase from 15,860 tons in 1976 to 43,239 tons in 1980. Iowa and Kansas account for more than 75 percent of the increase. Iowa's share of the Region VII total increases from 28 percent in 1976 to 41 percent in 1980. Six of the eight AQMA represented in the MFBI data are projected to have incremental increases greater than 1,000 tons in 1980. The largest increases are projected for the Missouri portion of the Kansas City AQMA and the Des Moines AQMA. The combined increases for these AQMA account for almost one-fourth of the Region VII total in 1980.

Incremental particulate emissions in Region VII are projected to increase from 1,676 tons in 1976 to 4,880 tons in 1980. The increases are most concentrated in Iowa, which is attributed with more than 55 percent of the total in 1980. Three AQMA are attributed with incremental increases of approximately 400 tons in 1980. These are Cedar Rapids and Waterloo in Iowa, and Kansas City in Missouri and Kansas.

Incremental sulfur dioxide emissions attributable to alternate fuel use in Region VIII are projected to increase from 7,233 tons in 1976 to 13,591 tons in 1980. The largest increase, more than 50 percent of the 1976 Region VIII total, is attributed to Montana. AQMA with projected emissions greater than 1,000 tons in 1980 include: Pueblo, Anaconda-Butte, Salt Lake City and Provo.

Incremental particulate emissions in Region VIII are estimated at 1,989 tons in 1976 and are projected to increase to 3,842 tons in 1980. More than 60 percent of the increase in 1976 is attributed to Montana. The increased emissions are most significant in the Anaconda-Butte AQMA, which accounts for almost one-third of the Region VIII total in 1980.

In Region IX, the incremental emissions of sulfur dioxide are projected to increase from 11,560 tons in 1976 to 51,691 tons in 1980. These emissions are primarily attributed to California and Arizona. Nevada's share of the emissions is less than one percent during the forecast period. California's share of the emissions increases from 67 percent in 1976 to 85 percent in 1980. Eight of the eleven AQMA represented by the MFBI data in Region IX are attributed with emissions in excess of 1,000 tons in 1980. Two California AQMA, Kern County and Southern Coast, are attributed with 44 percent of the Region IX total in 1980.

Region IX incremental particulate emissions are projected to increase from 2,125 tons in 1976 to 17,282 tons in 1980. California's share of the total is estimated at 79 percent in 1976 and 96 percent in 1980. The remainder of the emissions during the forecast period are attributed to Arizona. Quantitatively, the particulate emissions are most significant in the Southern Coast and San Francisco AQMA. Incremental emissions are projected to increase from 786 tons in 1976 to 12,247 tons in 1980 in the Southern Coast AQMA, while the increase in the San Francisco AQMA is estimated to increase from 624 to 2,412 tons during the forecast period.

Region X incremental sulfur dioxide emissions are projected to increase from 5,807 tons in 1976 to 9,874 tons in 1978 and then decline to 8,449 tons in 1980. The increases are primarily attributed to Washington, since Oregon's maximum yearly share of the total is less than 11 percent and Idaho's share is less than one percent during the forecast period. The Washington portion of the Portland-Vancouver AQMA and the Puget Sound AQMA are attributed with more than 60 percent of the Region X incremental sulfur dioxide emissions in 1978.

Incremental particulate emissions in Region X are projected to increase from 365 tons in 1976 to 754 tons in 1978 and then decline to 587 tons in 1980. Washington's share of the total varies between 70 and 100 percent during the forecast period. The remainder is almost entirely attributed to Oregon. Only one AQMA, Puget Sound, is projected to have incremental particulate emissions in excess of 100 tons during the forecast period.

NATURAL GAS SUPPLY AND CONSUMPTION IN THE UNITED STATES

For a number of years there has been a shortage of natural gas in the United States and this shortage is likely to continue. Gas supply has been insufficient to meet demand by existing industrial and electric utility users, and prospective residential and commercial users. As a result, emissions of sulfur dioxide and particulate matter have been higher than they would have been if more gas had been available.

The purpose of this chapter is to discuss gas supply and demand trends, emphasizing the industrial consuming sector and the role of natural gas in this sector. Particular attention is given to supply factors affecting the level of industrial gas consumption in the future. Various supply forecasts are reviewed and compared to provide a framework for the industrial gas consumption projections in Chapter I. As well, available data with respect to the near-term outlook for industrial gas availability are discussed.

Natural Gas Consumption in the U.S.

Natural gas accounts for nearly a third of total primary energy consumption in the U.S. The distribution of gas consumption in 1974[1] by sector -- residential, commercial, industrial and electric utility -- is set out on Schedule IV-1 as reported by the Gas Requirements Committee. Sheets 1 and 2 of the schedule report gas consumption in billions of Btu's by EPA Region and sheets 3 and 4 show the percentage distribution of gas consumption by sector for each region and state.

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[1] 1975 data are shown on sheets 5-8 of Schedule IV-1 but are not discussed in the text. Since the latest actual data for MFBI are 1974, it is appropriate that gross consumption data be discussed for the 1974 base period.

In 1974 gas consumption in the Lower 48 States was 19,542 trillion Btu's. Of this total, firm residential and commercial customers consumed 36.3 percent, firm industrial customers consumed 33 percent, firm electric utility customers consumed 11.2 percent, interruptible commercial customers consumed 1.5 percent, interruptible industrial customers consumed 11.5 percent, and interruptible electric utility customers consumed 6.4 percent.

Among the various EPA Regions, considerable variation occurs in the distribution of consumption by sector. For example, nearly 75 percent of gas consumed in Regions I and II was consumed by the residential-commercial sector. Conversely, industrial usage predominated in Regions IV, VI, and X where industrial sector consumption was, respectively, 52.2 percent, 57.3 percent, and 60.9 percent. Electric utilities, consuming 17.6 percent of gas consumed in the Lower 48 States, had gas usage of less than 5 percent in Regions I, III, V, and X. Largest electric utility sector shares of gas consumed were in Regions VI and VII -- 31.8 percent in the former and 24 percent in the latter. Review of the schedule also indicates considerable diversity in the distribution of consumption by state, both within and across EPA Regions.

Compared to electric utility and industrial gas consumption, residential-commercial gas consumption is relatively more evenly distributed across the 48 states. Approximately 56 percent of 1974 residential-commercial gas consumption occurred in 8 states -- California, Illinois, Ohio, Michigan, New York, Pennsylvania, Texas and Indiana, in descending order of importance.

In contrast, four states -- Texas, Louisiana, Oklahoma, and California -- account for 66 percent of electric utility gas consumption. Texas predominates, accounting alone for over a third of electric utility gas consumption.

More than two-thirds of industrial gas consumption occurred in 1974 in the eight states listed in the table below.

INDUSTRIAL GAS CONSUMPTION BY STATE
1974

	Trillions of Btu's	Percent of Lower 48 State Total
Texas	2,338	26.9
Louisiana	1,141	13.1
California	585	6.7
Ohio	436	5.0
Illinois	379	4.3
Pennsylvania	353	4.1
Michigan	348	4.0
Indiana	267	3.1
All Other States	2,857	32.8
Total	8,704	100.0

Source: Gas Requirements Committee

Texas, Louisiana, California, and Ohio were the four largest industrial gas consumers with a combined total of nearly 52 percent of Lower 48 State consumption. Regions V and VI were the leading industrial gas consuming regions with, respectively, 19.1 percent and 44.3 percent of Lower 48 State consumption.

Excluding California, in each of seven of the largest gas consuming states firm contracts dominate industrial consumption. Firm volumes are 90 percent or greater in Pennsylvania, Ohio, Illinois, and Texas, and as high as 98.5 percent in Louisiana. However, in California firm gas is only 15.1 percent of total industrial gas consumption, reflecting California regulatory policy of not allowing firm industrial contracts over 200 Mcf/day.

In most of the remaining states interruptible contracts are relied upon to a greater degree. A partial list includes Florida, Georgia, and South Carolina in Region IV; Wisconsin in Region V; Oklahoma in Region VI; Kansas and Missouri in Region VII; North and South Dakota, Montana, Utah, and Wyoming in Region VIII; and Washington in Region X.

In recent years, gas consumption by all sectors has declined, in part due to warm weather, conservation and the economic recession, and in part due to insufficiency of supply. Schedule IV-2 shows trends in the supply and consumption of natural gas in the Lower 48 States since 1960.

Residential-commercial gas consumption increased each year from 1960 to 1972, at an annual average rate of 5.0 percent. Since its 1972 peak, it declined by 3.2 percent in 1973, 1.7 percent in 1974, but increased 1.9 percent in 1975. The declines are attributable to warmer than normal weather, conservation which first occurred during the Oil Embargo and has persisted thereafter, and limitations on the attachment of new customers which are prevalent in various parts of the U.S.

Electric utility gas consumption, which increased rapidly to 1971, has decreased even more rapidly since a negligible decline in 1972. In 1973 gas consumption dropped 9.5 percent, in 1974 gas consumption dropped 5.0 percent, and in 1975 gas consumption dropped 8.4 percent.

Industrial gas consumption peaked in 1973 and has declined sharply since then. In 1974, industrial gas consumption dropped 5.0 percent and in 1975 it dropped a further 16.2 percent. Available information for the first few months of 1976 indicates a further but not nearly as large reduction compared with the like period in 1975.

The Role of Natural Gas in Fulfilling Energy Requirements by Sector in the U.S.

Gas competes in varying degree with other forms of energy in all market sectors. The discussion in this section focuses on the role of gas as an energy source vis-a-vis other fuels in the consuming sectors, especially the industrial sector. Energy consumption by stationary users in 1974 is set out by sector, EPA Region and state on Schedule IV-3. Sheets 1-2 show the distribution by fuel type in the residential-commercial sector;[1] sheets 3-4 show the distribution by fuel type in the industrial sector; and sheets 5-6 show the distribution by fuel type in the electric utility sector.

Especially with respect to the industrial sector, it is important to note that the data on IV-3 cover all users in each sector. The MFBI data with respect to large combustors discussed in previous chapters which are the focal point of this study comprise only a portion of the industrial sector. It is estimated that the large industrial combustors analyzed by this study account for 33 percent of industrial gas consumption and 44 percent of industrial energy consumption.

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[1] The sources of data do not permit a basis for separating the residential and commercial sectors of the market.

With respect to the residential-commercial sector, gas is the dominant fuel in the United States. Of total residential-commercial energy use, gas accounted for 49.5 percent. Fuel oil and electricity follow in importance with 22.9 and 21.5 percent, respectively. Least significant are coal and LPG with a combined total of 6.1 percent.

Fuel dominance and the energy mix vary significantly by EPA Region and state within the residential-commercial sector. In 1974, gas was the dominant residential-commercial fuel in Regions III, V, VI, VII, VIII and IX, with shares of energy consumption greater than 50 percent and as high as 68.2 percent in Region IX. Distillate fuel oil predominated as an energy source in Regions I and II with 59.1 percent and 43.9 percent of Btu's consumed, respectively. Electricity was the most important energy source in Regions IV and X -- 39.2 percent of Btu's consumed in the former and 41.7 percent of Btu's consumed in the latter.

In the electric utility sector coal is the primary fuel utilized to generate power. Excluding electricity generated for hydro and nuclear, coal accounted for 55.4 percent, gas for 22.4 percent, residual fuel oil for 19 percent and distillate fuel oil for 3.2 percent.

Residual fuel oil is the predominant electric utility fossil fuel in Regions I and II, followed by coal. Residual fuel oil is also predominant in Region IX, followed by gas. Coal is predominant in Regions III, IV and X, followed by fuel oil in varying degree, and in V, VII, and VIII, followed by gas. Gas is predominant only in VI, followed by coal.

Gas is the dominant energy source for industrial users. In 1974, industrial sector energy consumption amounted to 12,887 trillion Btu's. Of this total, gas accounted for 8,704 trillion Btu's, or 67.5 percent; residual fuel oil[1] for 2,054 trillion Btu's, or 15.9 percent; coal for 1,578 trillion Btu's, or 12.3 percent; distillate fuel oil for 449 trillion Btu's, or 3.5 percent; and LPG for 102 trillion Btu's, or 0.8 percent.

Again, as in the other sectors, fuel dominance and energy mix vary significantly by EPA Region and state. In 1974, gas dominated as an industrial energy source in all EPA Regions except Regions I and II, where residual fuel oil was by far the most important energy source, accounting for, respectively, 80.2 percent and 65.5 percent of industrial energy consumption. Gas utilization ranged from as low as 13.8 percent of industrial energy consumption in Region I to as high as 79.3 percent in Region IX and 93.2 percent in Region VI. Coal was most significant as an industrial energy source in Regions III and V, accounting for about 26 percent of all Btu's consumed by industrial users. In addition, coal and oil competed more or less equally as industrial energy sources in Regions III, IV and VIII; and, excluding relatively insignificant LPG use, industrial energy consumption in Region II was more evenly distributed among fuel oil, gas, and coal than in all other EPA Regions.

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[1] Includes No. 6 heating oil and all other residual type oils sold to industrial customers and oil companies.

The relative roles of gas, residual fuel oil, and coal as industrial energy sources are seen from the table below to vary significantly in several of the largest industrial energy consuming states.

INDUSTRIAL ENERGY CONSUMPTION BY STATE
1974

		Percent Distribution by Fuel Type					
			Fuel Oil				
	Trillions of Btu's	Gas	Distillate	Residual	Coal	LPG	Total
Texas	2494	93.7%	1.4%	2.3%	2.4%	0.2%	100.0%
Louisiana	1203	94.9	2.2	1.8	-	1.1	100.0
Ohio	792	55.1	4.3	4.0	36.2	0.4	100.0
California	734	79.7	4.1	14.1	0.1	2.0	100.0
Pennsylvania	696	50.7	3.6	24.3	20.7	0.7	100.0
Illinois	627	60.4	2.7	18.1	17.7	1.1	100.0
New York	550	20.3	2.7	67.0	9.5	0.5	100.0
All Other States[a]	5791	58.0	4.6	20.5	16.0	0.9	100.0
Total	12887	67.5	3.5	15.9	12.3	0.8	100.0

[a] Excluding Alaska and Hawaii.

In Texas and Louisiana, where 1974 industrial energy consumption was about 29 percent of the Lower 48 State total, gas utilization accounted for greater than 90 percent of industrial energy consumption. Though not to the same extent, California is similar to Texas and Louisiana in that gas was the primary fuel burned for industrial purposes. Conversely, in New York, where residual fuel oil dominated with 67 percent of 1974 industrial energy consumption, gas for industrial use accounted for only 20.3 percent of Btu's consumed.

Illinois, Pennsylvania, and Ohio, states where gas was the dominant fuel, differ from Texas, Louisiana, and California, not only in the degree of dependence on gas as an industrial energy source, but also in that coal and/or residual fuel oil were more significant factors in the energy mix. Whereas coal accounted in 1974 for 36.2 percent and residual fuel oil for 4 percent of industrial energy consumption in Ohio, coal and residual fuel oil had more equivalent shares of industrial Btu's consumed in Pennsylvania and Illinois. Residual fuel oil was a more significant factor in Pennsylvania than in Illinois, accounting in the former for about 24 percent of industrial energy consumption, and in the latter for approximately 18 percent. Coal, though not as important an industrial energy source as in Ohio, accounted for 20.7 percent of industrial Btu's consumed in Pennsylvania and 17.7 percent of industrial Btu's consumed in Illinois.

Trends Underlying The Current Gas Shortage In The U.S.

It is evident that the Nation's gas supply picture has been deteriorating for some years, as shown on Schedule IV-4. Proved reserves have been declining since 1967, although production increased during most of this period. Production peaked in 1973, and declined in 1974 and 1975 by nearly [illegible] percent and eight percent, respectively. It is estimated that during the first eight months of 1976, production has further declined by slightly over two percent.

The precipitous drop in proved reserves since 1967, culminating in declining production, reflects the failure of reserves additions to replace production. In 1968 reserves additions were less than production for the first time since World War II, and this situation has continued in the Lower 48 States every year since 1968. From 1971 to 1975, reserves additions have averaged 8.8 Tcf per year, thus replacing only 41 percent of production during this period.

This low level of reserves additions in part reflects large negative revisions to previous estimates incorporated in more recent estimates. These changes in previous estimates may result from geologic or engineering data provided by additional drilling, production history, or the application of cycling or other recovery techniques. Exclusive of all revisions (both positive and negative) reserve additions have averaged 10.1 Tcf per year for the last five years.

With respect to interstate markets for natural gas, trends in production and reserves additions reflect a worse picture than the Nation as a whole. Schedule IV-5 shows that over the last five years, reserve additions have replaced only three percent of production - considerably below the experience for the Nation as a whole. Interstate production peaked in 1972, a year before total production in the U.S. peaked. Thereafter, interstate production has declined steadily at a faster pace than overall U.S. production - by 3.5 percent in 1973, 5.1 percent in 1974, 6.9 percent in 1975, and by 4.9 percent for the first five months of 1976. These adverse trends reflect the difficulty faced by interstate pipelines in competing for new onshore gas supplies against intrastate purchases which are not restricted by FPC price ceilings.

In recent years the primary source of new gas reserves for interstate pipelines has been offshore areas of the U.S., primarily the Louisiana portion of the Gulf of Mexico. It is evident from Schedule IV-5, however, that the experience of interstate pipelines in the Gulf of Mexico has not been able to offset the impact of onshore developments.

Schedules IV-6 and IV-7 show trends in production and reserves additions for major producing areas in the United States. With respect to production, the data on Schedule IV-6 reveal the increasing importance of offshore South Louisiana. By 1975, this area accounted for 17 percent of total production in the Lower 48 States compared with 10 percent in 1970 and 2 percent in 1960. Offshore South Louisiana accounted for a substantial portion of the growth in Lower 48 production from 1965 to 1970 and was the only major producing area between 1970 and 1975 to experience any substantial growth. From 1974 to 1975 production declined significantly in all major producing areas except offshore South Louisiana, where production increased by only 0.6 percent, its lowest annual growth since before 1960.

A generally similar picture is evident with respect to reserves additions. Again, offshore South Louisiana accounted for a major share of Lower 48 reserve additions since 1967, approximately one-third. Comparing reserves additions for the 1960-1967 period with the 1968-1975 period, average reserve additions during the more recent period declined substantially in all major producing areas except the offshore South Louisiana, Hugoton-Anadarko and Rocky Mountain areas. Reserve additions in the latter two areas, however, have been nevertheless insufficient to replace production during this period.

Underlying these trends in reserves additions are two major components thereof - well drilling and productivity. The term productivity refers to the relationship between exploration inputs (e.g., well drilling) and outputs or the results (e.g., reserves additions). As used herein, the term productivity refers to additions of non-associated gas reserves per foot of gas well drilled.

Schedule IV-8 shows trends in well drilling in the Lower 48 States. As shown on the schedule, well drilling - successful oil and gas wells and dry holes - steadily declined from 1960 to the early 1970's. This decline in well drilling in large measure explains the drop in reserves additions beginning in the late 1960's. But, applicable to all well drilling and particularly gas, the level of well drilling has increased substantially in recent years. Gas well drilling is now at record highs. As shown on the following table, most of the increase in gas well footage has been onshore.

TOTAL U.S. GAS WELL FOOTAGE
(thousands of feet)

	Onshore	Offshore	Total
1971	20,463	2,161	22,624
1972	25,109	1,656	26,765
1973	33,078	2,522	35,600
1974	37,249	1,728	38,986
1975	39,999	1,929	41,927

During the first half of 1976, total gas well footage, both onshore and offshore, has increased still further. The steep rise in onshore footage during the 1970's is generally attributed to the substantial increases in gas prices for intrastate markets.

Despite the overall increase in gas well footage, reserve additions have not increased. The decline in the productivity of drilling in recent years has been responsible. Schedule IV-9 shows additions to reserves per foot of gas well drilled. The data vary erratically from year to year and even five year moving averages do not display a smooth trend. Nevertheless, the data show that productivity during the period 1969 to 1975 was sharply lower than in prior years, varying between 113 Mcf per foot to 475 Mcf per foot compared to an average of 616 Mcf per foot from 1958 to 1968. In its most recent new gas rate determination - Opinion 770 discussed more fully at a later point - the Federal Power Commission employed a productivity factor of 300 Mcf per foot.

It is evident from the foregoing discussion that the continued low level of reserves additions has been in large degree brought about by the sharp decline in productivity. Some particular comment seems in order concerning the future productivity of drilling in light of the conspicuous decline since 1969. In the longer-term, it may be anticipated that productivity will decline as the volume of remaining reserves to be found decreases. This long-term tendency may, nevertheless, be subject to short-term unpredictable reversals as new petroleum provinces are opened up in the exploration process.

Recent Natural Gas Pricing Developments

The price of natural gas in the field obviously influences the incentive to find additional gas, and thus the purpose of this section is to briefly discuss natural gas pricing developments which will influence gas supply to 1980.

An important factor which explains the inability of interstate pipelines to acquire new onshore gas reserves has been the wide disparity between the ceiling price interstate pipelines could pay and the prices being offered by intrastate purchasers. This problem has existed for a number of years, but the difference between interstate and intrastate prices has been increasing. Prior to 1972, the intrastate purchaser needed only to offer a modest premium over interstate prices to obtain gas. Competition among intrastate purchasers increased subsequently as the gas shortage worsened, and prevailing intrastate prices soared. In 1974 intrastate prices averaged 92¢/Mcf, compared with the 51¢ national rate promulgated by the FPC at the end of that year and lower rates prior thereto. By the second quarter of 1976, the average price for new intrastate contracts reached $1.59/Mcf. There are, of course, variations in these prices by area, but it is generally believed that these intrastate prices have elicited the substantial upturn in gas drilling in onshore areas.

In July of 1976, the FPC increased the national rate for new gas to $1.42/Mcf. This was equivalent to somewhat less than a doubling in prospective price to the producer, after adjustment for tax and royalty components.[1] The new national rate remains below prevailing intrastate prices in most onshore areas, and thus will have only a limited impact on onshore gas acquisitions by interstate pipelines. However, the new rate should provide a greater incentive than would have existed otherwise for offshore drilling.

Producers can also apply to the FPC for special relief, or higher prices, if "out-of-pocket" expenses exceed revenues. Prior to the release of the $1.42 rate determination, the FPC approved a number of prices above the then existing national rate on the basis of cost. The future direction of the FPC in special relief cases cannot be assessed at this time.

Particularly applicable to industrial gas supply and to a few MFBI is the FPC's Order 533 procedures, although not a pricing policy *per se*. The FPC's Order 533, adopted October 1975, makes available natural gas supplies to industrials in the interstate market from the intrastate market.

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[1] Due to the elimination of the depletion allowance, the FPC included income taxes as a cost in the $1.42 derivation which was not included in the earlier $0.51 derivation.

Under the terms of this policy, jurisdictional pipelines who are granted transportation certificates of public convenience and necessity may transport natural gas supplies purchased by an industrial or commercial customer from an independent gas producer for non-resale, high priority end-uses (Priorities 2 and 3), for delivery at the customer's plant. This procedure is subject to the following conditions:

1. The transporting pipeline must be curtailing deliveries of gas to its customers and have available unused capacity to transport natural gas.

2. The pipeline must be capable of ascertaining a firm price to be paid.

3. The Order 533 volume is not considered part of the pipeline's available supply, therefore, it is not subject to the Commission's curtailment policies.

4. The Order does not apply to gas sold by an affiliate of a jurisdictional pipeline or gas sold by a producing division of such a pipeline.

5. The certification period is for a maximum of two years.

6. The Order applies only to existing customers whose deliveries for high priority uses are curtailed because of curtailments by the jurisdictional pipeline supplier, or whose deliveries are subject to imminent curtailment.

7. Since purchasers buy directly from the producers, sales are non-jurisdictional.

8. The Order applies only to customers who have no alternate fuel capabilities for their combustors, and require a minimum of 50 Mcf per peak day.

9. Purchasers must submit a monthly report to the transporting pipeline, who in turn submits it to the FPC, containing the amount of gas consumed and for what end-use in that month.

10. A detailed description of the nature of the emergency must also be provided.

Very significant curtailments have been experienced by Transcontinental Gas Pipeline, Columbia Gas Transmission, Texas Eastern Transmission and Panhandle Eastern Pipeline. It is predominantly those four who have filed applications for Order 533 transportation certificates.

Approximately 54 industrial companies with a total volume of 52 Bcf per year have been granted such certificates. Ten MFBI are included, with a volume of 2,819.5 Mmcf per year of gas to be transported as compared with 3,761.8 Mmcf of gas consumed by their major combustors in 1974. The emergency gas represents 75 percent of the 1974 gas consumption in major combustors for these MFBI.

Of the 10 plants included, a majority are in the textile manufacturing industry with a few in the agricultural chemicals and paper manufacturing field. All are located in EPA Region IV with the exception of one which is in Region III. The emergency gas is transported by Transcontinental Gas Pipeline for all plants with the exception of one being transported by Tennessee Gas Pipeline. The volume of emergency gas for the MFBI in Region III is 620.5 Mmcf per year as compared with 339.9 Mmcf consumed in their major combustors in 1974. In Region IV the volume is 2,199.0 Mmcf per year for the 9 MFBI compared with 3,421.9 Mmcf of gas consumed by their major combustors in 1974.

According to their applications, these plants were faced with total or near-total plant shutdown, plant lay-offs and production cutbacks because of their essential need for natural gas and the resultant curtailments. For the textile companies natural gas is necessary for their process needs in a number of direct-fired finishing operations. The heat-setting and resin curing of some plants require an even flame which can only be achieved with natural gas or propane. The agricultural chemical plants utilize natural gas in direct-fired operations in nodulizing kilns which require intense heat for calcining, plant protection (Priority 2) and processing usage (Priority 3); also used in applications to generate process steam, operate incinerators and sulphur deodorizing units in the manufacture of pesticides.

Of the ten MFBI authorized to receive Order 533 gas, nine will use it in combustors other than those considered. The pertinent MFBI intend to use the emergency gas in smaller process combustors, while the combustors which are studied herein are large boilers. Thus, it is apparent that Order 533 volumes to industrials authorized to date will have a limited effect on the shortages forecast in this study.

Comparison of Forecasts of U.S. Gas Supply

Schedule IV-10 compares recent estimates of Lower 48 gas production by government and industry sources. As discussed earlier, Lower 48 production has already declined substantially, from 22.5 Tcf in 1973 to 19.6 Tcf in 1975. The striking feature of all the forecasts depicted on Schedule IV-10 is the unanimity of opinion that production will continue to decline to 1980 and thereafter, unless gas prices are deregulated. Even with deregulation, those forecasts which assume these higher prices indicate only modest increases in production.

The FPC Bureau of Natural Gas prepared three alternate forecasts of gas production, termed "Low," "Medium," and "High." The "Low" case, which shows nearly a two-thirds reduction in gas production to 1985, assumed no reserves additions and is thus useful only for illustrative purposes. Basically, this forecast indicates a 9.4 percent annual decline in production from existing proved reserves. In the "Medium" forecast, which could be characterized as a continuation of trends since 1968, reserves additions were assumed to be at levels experienced from 1969 to 1973. With reserves additions averaging approximately 9.5 Tcf per year, this forecast indicates a 3.4 percent annual decline in production to 1985. The "High" forecast assumes reserves additions of 14.7 Tcf, the average between 1960 and 1973, and this forecast indicates a 1.2 percent annual decline to 1985. Since the base year for the FPC projections was 1973, and actual reserves additions during 1974 and 1975 have been lower than forecast in the "High" case, the "High" production forecast in 1980 may be slightly overstated.

The Gas Requirements Committee (GRC) forecast is comparable to the FPC "Medium" case, and seems to reflect a continuation of recent trends. Since the GRC summarizes projections of individual gas companies throughout the U.S., this forecast does not specify assumptions. Each company makes its own assumptions regarding gas supply and regulatory climate. Thus, the GRC forecasts reflect the best estimates of sellers of gas as to future supply and consumption of gas.

Shown next on the schedule is the most recent forecast by the U.S. Department of Interior. Interior also forecast a steady decline, but at a slightly lesser rate than the "Medium" FPC and GRC forecasts. Important assumptions made by Interior regarding gas supply are--1) deregulation of oil prices; 2) relaxation of Federal Power Commission wellhead price controls; and 3) continued leasing of the Federal offshore areas at the accelerated pace currently proposed by the Department of Interior.

The Federal Energy Administration generated six forecasts of Lower 48 production with their PIES models, all of which are shown on Schedule IV-10. Four of the scenarios assume deregulation of both oil[1] and gas, while two assume continued price regulation for gas. All the forecasts shown assume world oil prices of $13/bbl. in 1975 dollars. The reference deregulation case shows a very slight increase in production in 1985, the optimistic deregulation case shows a larger increase, and the pessimistic deregulation case shows a marked decline. The various deregulation cases make different assumptions as to the amount of potential gas remaining to be discovered, the amount of OCS leasing, and the investment tax credit. Under deregulation (the reference or base case) FEA projects a significant improvement in interstate supply, but a reduction in intrastate supply.

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[1] Oil prices and hence oil production affect associated-dissolved gas production.

The FEA Projection of Interstate and Intrastate Net Domestic Supplies[a]
(Tcf)

	Present Regulation		Deregulation	
	Interstate	Intrastate	Interstate	Intrastate
1974	11.6	7.2	11.6	7.2
1985	6.6	9.3	12.1	7.9

[a] Gas consumed by end-users, excluding SNG and imports but including Alaskan gas.

The next forecast depicted on Schedule IV-10 is by Shell Oil Company. Shell's projection appears to reflect a continuation of recent trends and is comparable to the FPC "Medium" case and the GRC forecast.

Three forecasts by the American Gas Association (AGA) are shown. The AGA deregulation projection indicates a virtually imperceptible increase in gas production. Of the available forecasts, AGA was the only source to project gas production, assuming regulation, taking into account the recent upward revision in the national interstate rate. This forecast shows production declining, but not falling to the levels that would occur if current trends were maintained. With respect to the AGA forecasts, it should be noted that substantial East Coast Offshore production is projected for 1985.

Future gas consumption will not, of course, be limited to conventional Lower 48 production. At the present time, imports of Canadian gas account for nearly 5 percent of U.S. consumption and propane air and SNG for about 2 percent. Additionally, it is expected that Alaskan gas, imported LNG, and increased volumes of SNG will play an important role in meeting gas requirements. Schedule IV-11 compares forecasts of total gas supply in 1980 and 1985 by four of the sources previously discussed in the context of conventional production.

For both 1980 and 1985, three of the four sources show very similar projections - a small decline from 1974 levels. The mix and volumes of supplements varies among GRC, Interior and Shell Oil, but the totals are comparable. FEA's 1985 total supply, which also assumes deregulation, is substantially higher. However, FEA's total is less of a projection of what will be, and this projection should be construed as what could be if various positive actions are taken.

The GRC forecast of total gas supply is shown by component - SNG, propane air, and LNG - on Schedule IV-12. Substantial and increased amounts of SNG and LNG are projected to 1980 and 1985. To 1980, the forecast of SNG from liquid hydrocarbons, which are the largest components of the total SNG, is deemed reliable because it is apparently based largely on plants already constructed. However, the SNG forecast includes coal gas in the amount of 34 trillion Btu's in 1979 and 96 trillion Btu's in 1980 which probably reflects a plant contemplated to serve the West Coast. Since the publication of the GRC forecast, this plant has experienced delays in go-ahead and likely will not be in full operation by 1980. Also experiencing delays have been the East Coast LNG projects which are reflected in the GRC projections beginning in 1976.

The GRC Forecast Of Consumption

Of all the forecasts discussed, only GRC projected gas consumption regionally (and by state) by sector. Schedule IV-13 shows the GRC consumption projection by sector and EPA region. Since the GRC forecast is made by gas sellers, who make their own assumptions as to supply and regulatory climate, the GRC forecast reflects company marketing strategies and regulatory curtailment strategies. The GRC supply forecast to 1980 appears to represent the concensus of opinion, and hence the resultant forecast of consumption under these supply conditions is extremely useful.

National gas consumption at the end-use level[1] is projected to decline from 19,541 trillion Btu's in 1974 to 17,347 trillion Btu's in 1980 - an annual rate of decline of 2 percent. Forecast trends by sector are divergent, however, with residential and commercial consumption increasing and industrial and electric utility use decreasing. Residential and commercial consumption are expected to grow at annual rates of 2.2 percent, while industrial use is projected to decline at a rate of 4.2 percent, and electric utility use is projected to decline at a rate of 7.3 percent.

These trends reflect prevailing marketing and curtailment strategies by gas companies and regulatory agencies. New residential and commercial customers are being added in some parts of the country, while existing industrial and electric utility gas users are being curtailed. Most affected are interruptible electric utility and industrial gas users. The combination of generally declining or even stable gas supply and increasing higher priority consumption results in large declines in the availability of gas for lower priority uses.

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[1] Lower 48 states only. Includes gas usage in the residential, commercial, industrial, and electric utility sectors; excludes gas consumed for field use and gas usage not accounted for in specific categories (i.e., pipeline fuel, company use, transmission loss).

These trends are generally projected for all EPA regions but in varying degree. Residential consumption is shown to increase in every region, and commercial consumption is shown to increase in all regions except Region III. Industrial consumption is anticipated to decline in all regions except Region X, where 0.6 percent annual growth is expected. Declines range from 1.3 annually in Region I[1/] to 6 percent in Region III and 8.6 percent in Region IV. Generally, interruptible industrial consumption is shown to decline more severely than firm consumption. Substantial declines in electric utility consumption are projected in all EPA Regions.

Sources of Gas Supply By State

Schedule IV-14 shows the sources from which each state obtained its gas supply in 1974. Reading downward, the columns show the percentages of total state consumption which were delivered by each of the major interstate pipelines, by the other interstate pipelines grouped together, and also the percentages derived from production within the state and delivered by intrastate facilities.

Region I was almost completely dependent on two pipelines, Tenneco and Texas Eastern. New Hampshire was entirely served by Tenneco while Connecticut and Massachusetts received

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[1/] This decline occurs in 1976, after which consumption is shown to increase, presumably due to anticipated receipt of LNG.

about half of their supplies from Tenneco and half from Texas Eastern via Algonquin. In Massachusetts, the Boston and Providence areas in the East were served mainly by Texas Eastern and the rest of the state mainly by Tenneco. The supply of gas to Vermont was entirely from Canadian sources.

In Region II, Transcontinental was the chief supplier. New Jersey received 60 percent of its gas from Transcontinental, 34 percent from Texas Eastern and 6 percent from Tenneco. The northern part of the state, and parts of the southwest were served by Transcontinental and Texas Eastern supplied Ocean County in the east. New York received 29 percent of its gas supply from Consolidated which supplied gas in Rochester and across the center of the state. Transcontinental supplied 29 percent and was important in the area close to New York City. Columbia, Tenneco and Texas Eastern each contributed 6 or 7 percent of the state's total supply. Columbia supplied Binghamton, and Tenneco and Texas Eastern brought part of the supply to the northwest. A further 21 percent of New York's gas was supplied by Tenneco, Consolidated and others through the National Fuel Gas Supply and Distribution Corp. and this gas was mostly delivered in the Buffalo area.

In Region III, Delaware was entirely supplied by Transcontinental and Maryland almost entirely by Columbia with about 2 percent from Transcontinental in the East.

Pennsylvania received 27 percent of its gas from Columbia, 15 percent from each of Texas Eastern and Transcontinental, 17 percent from Consolidated and 6 percent from Tenneco. A further 12 percent came from National Fuel Gas which itself obtained most of its gas from these five major pipelines. The Philadelphia area was served mainly by Texas Eastern and Transcontinental and the southwest mainly by Columbia, Texas Eastern and Tenneco. Consolidated contributed some of the gas in the northwest. Pennsylvania also received 6 percent of its gas from intrastate suppliers.

The greatest part of Virginia supplies (62 percent) came from Columbia. The state also received 32 percent from Transco and 6 percent from Tenneco. Columbia gas went to most parts of the state. Transco supplied Danville, and contributed with Columbia to the southeast. Tenneco contributed to the supply in the Valley of Virginia.

In West Virginia, over half (56 percent) of the supply came from Columbia which provided gas in the Charleston, Huntington and Bluefield areas and also in Wheeling. Relatively small amounts of gas came from Consolidated and Tenneco, and over a third of the total supply was locally produced, and delivered by intrastate lines.

In Region IV, Southern Natural was the most important supplier, serving gas in six of the eight states in the region and bringing 60 percent or more of the total supply to three of them. In Alabama, 60 percent of the supply was provided by Southern Natural, 13 percent by each of Tenneco and United, some smaller amounts by other pipelines and 8 percent was intrastate gas. Southern Natural, through the Alabama Gas Corporation, served the Birmingham and Montgomery areas, and central and southeast Alabama. Tenneco provided gas in the Tennessee River Valley area in the north and United was the chief supplier in the Mobile area in the southwest.

Four-fifths (82 percent) of the gas requirements in Florida were provided by Florida Gas Transmission Co. It supplied the area around Jacksonville in the north, and was the sole supplier for central and southern Florida. United was the next largest supplier, bringing 11 percent, and it served the Pensacola area in the northwest. Southern Natural contributed 3 percent and served the area surrounding Tallahassee in the north. Florida also had some intrastate supplies, amounting to 4 percent of the total.

Georgia depended on two suppliers only. Southern Natural provided 89 percent and served gas in all parts of the state. Transcontinental supplied the remaining 11 percent in the north and northeast parts of the state.

The chief supplier in Kentucky was Texas Gas, providing 55 percent of supplies. The next largest was Columbia with 23 percent, and Tenneco provided 13 percent. The main distributor in the western third of the state, the West Kentucky Gas Co., was supplied by Texas Gas and Tenneco - Texas Gas being most important in the west. Texas Gas also supplied the Louisville area and north central Kentucky. Columbia Gas supplied the Lexington - Richmond - Winchester area and Tenneco supplied Ashland. Kentucky also had some local production and 3 percent of total supplies came from intrastate sources.

In Mississippi, gas was provided by ten of the major pipelines but six of these contributed 2 percent or less of total supplies. The largest supplier was United, bringing 35 percent; Southern Natural brought 13 percent; Texas Gas 10 percent; and Tenneco 9 percent. A further 21 percent of supplies was due to "other interstate pipelines," most of this coming from offshore Louisiana. Southern Natural served the Vicksburg and Yazoo areas; and United supplied gas in central and southeastern Mississippi, except for Standard Oil's refinery at Pascagoula which was supplied direct from offshore Louisiana by means of its subsidiary, the Chandeleur Pipeline Company.

The entire requirements of North Carolina were supplied by Transcontinental.

South Carolina was served by Transcontinental in the north, bringing 29 percent of the total supply. The southern part of the state, including Columbia and Aiken County, was supplied by Southern Natural which provided 71 percent of the total supply.

Tennessee received 53 percent of its gas requirements from Tenneco. This pipeline supplied Nashville and its environs and all the eastern half of the state, comprising the Chattanooga, Knoxville and Johnson City areas. Southern Natural contributed part of the Chattanooga supply. Texas Gas supplied 35 percent of the state's consumption, providing gas for the Memphis area where there are eight MFBI and also for Jackson in Madison County. Hardin and Humphreys Counties are served by Tenneco.

In Region V, the chief suppliers were Columbia, Michigan-Wisconsin, Natural, Northern and Panhandle. The predominant supplier in Illinois was Natural, which supplied 64 percent of requirements. This company served the Chicago area (Cook and Wills Counties) where most MFBI were located, and most other parts of the state including the Decatur area and East St. Louis. Panhandle provided 13 percent of total requirements in the central part of the state and in the northwest. Midwestern provided 10 percent, mainly in the northeast, and Mississippi River brought 5 percent in and around East St. Louis.

Indiana received one-third of its supplies from Panhandle, 27 percent from Natural, 19 percent from Texas Gas and 17 percent from Midwestern. Nearly half of the MFBI in Indiana were in the northwest corner, in Lake County. The gas for the northern part of the state came mainly from Panhandle, Natural and Midwestern. Central Indiana (Indianapolis, Anderson and Muncie) was served by Panhandle and Michigan-Wisconsin. Texas Gas supplied Terre-Haute, in Vigo County and the southern parts of the state including Posey County in the southwest and Clark County in the southeast. Dearborn County was supplied by Texas Eastern.

In Michigan, the chief supplier was the Michigan-Wisconsin Pipe Line Co. which delivered half of the total state requirements. The next in importance was Panhandle, with 15 percent, then Trunkline with 17 percent. Most MFBI in Michigan were concentrated in the Detroit area which is served mainly by Michigan-Wisconsin and Panhandle. Michigan-Wisconsin served west central Michigan, including Grand Rapids and Muskegon, and also the northwest, but the Ishpeming area was supplied by Northern. The southwest and south central areas and also the east central area around Midland, Saginaw and Bay City, were supplied by Panhandle and Trunkline. Local producers contributed 8 percent to Michigan's supplies via intrastate sales.

Minnesota was almost completely dependent on Northern Natural Gas Co. which delivered 93 percent of supplies. Midwestern contributed 2 percent and some Canadian gas is imported.

More than half of the gas used in Ohio was supplied by Columbia. Consolidated provided 29 percent, Panhandle 7 percent, and 6 percent came from intrastate supplies. Columbia delivered gas in most parts of the state, the main exception being the city of Toledo, which was served by Panhandle, and the northeast (Cleveland, Akron, Canton and Youngstown area) which was served in part by Panhandle but mainly by Consolidated. Marietta was also served by Consolidated.

Wisconsin was served mainly by the Michigan-Wisconsin Pipe Line Co. which brought 92 percent of the supply. Northern Natural Gas supplied 7 percent and was important in the Eau Claire and La Crosse districts.

In Region VI, intrastate withdrawals far exceeded the amounts of gas delivered by the interstate pipelines although the proportions differed as between states. In Arkansas only 12 percent of the supply was intrastate. Arkansas-Louisiana Gas Co. provided 80 percent (some of this being gas produced in Arkansas). Mississippi River contributed about 2 percent, supplying gas in Fort Smith, Blytheville and some districts in the south of the state. A further 2 percent was supplied by Natural.

In Louisiana 85 percent of the gas supply was from intrastate sources. Most of the remainder was brought by United, which served gas in New Orleans, Norco and other parts of the south. Arkansas-Louisiana supplied gas in the Shreveport area in northwest Louisiana.

Intrastate supplies in New Mexico amounted to 70 percent of the total supply. Almost all of the interstate gas came from El Paso which supplied Southern Union Gas Co., the chief distributor in the state, serving the Albuquerque and Silver City areas.

Oklahoma received 57 percent of its gas supply from intrastate suppliers. Of the remainder, Arkansas-Louisiana brought 4 percent and served gas in Stephens and Pontotoc Counties; Cities Service brought 3 percent and served Oklahoma City, while some areas in the south and southeast were supplied by Texas producers via the Lone Star Gas Co.

If gas supplied by Lone Star within Texas is included in intrastate supplies, only 7 percent of the requirements of Texas were delivered by interstate pipelines. Of this, El Paso supplied 2 percent, and Northern and United each contributed 1 percent.

In Region VII, there was not much local production except in Kansas. The chief supplier in Iowa was Northern, which supplied nearly two-thirds of the gas used. About a quarter was delivered by Natural and the rest by Michigan-Wisconsin. Northern was the sole supplier in the northern half of the state, Natural contributed in Des Moines and served the Cedar Rapids, Clinton and Davenport areas. Michigan-Wisconsin brought supplies to the south and southeast.

In Kansas, 27 percent of the gas supply in 1974 was from intrastate sources. Two-thirds of the remainder (48 percent of total supplies) was delivered by Cities Service and 13 percent was brought by Northern. Kansas-Nebraska, providing

9 percent, served the northwest corner, Arkansas-Louisiana delivered supplies in Rice and Reno Counties in the middle of the state. Cities Service was predominant in Kansas City, Topeka and the southeast.

Cities Service was also the chief supplier in Missouri, delivering 49 percent of total requirements. Mississippi River brought 35 percent and Panhandle 11 percent. The west of the state was served mainly by Cities Service, with some gas from Panhandle in the Kansas City area. In the east, Pike County was supplied by Panhandle, and St. Louis and Genevieve County by Mississippi River.

In Nebraska, Northern supplied most of the gas (61 percent) serving Omaha and Cass and Lancaster Counties in the east. Kansas-Nebraska provided 31 percent over a wide area including Scottsbluff in the west. Nuckolls County in the south was supplied by Cities Service.

Region VIII contains North and South Dakota, and four other states grouped together. There was one MFBI in each of the Dakotas. In North Dakota, the plant had main line delivery from Montana-Dakota, and in South Dakota the plant was in the southeast and would have been served by Northern. In the other four states of this region, Colorado, Montana, Utah and Wyoming, the chief supplier was Colorado Interstate which brought 38 percent; intrastate sales accounted for 24 percent; Mountain Fuel for 19 percent; and Montana-Dakota for 4 percent. In Colorado, most MFBI were in the Denver area which was served by Colorado Interstate. This pipeline served all MFBI except those in Logan and Sedgwick Counties in the northeast which were dependent on Kansas-Nebraska.

In Montana, the southwest of the state was served by Montana Power which was mainly supplied by Canadian imports. The Billings area was served by Montana-Dakota.

Utah was supplied 99 percent by Mountain Fuel. Wyoming was served by Montana-Dakota in the north, by Mountain Fuel in Sweetwater County, by Kansas-Nebraska in the Casper area and in Carbon and Goshen Counties, and by Colorado Interstate in the southeast.

In Region IX, Arizona received all but 1 percent of its gas from El Paso. This pipeline also supplied half of the gas used in California, mainly in the southern half of the state. California also had a significant supply of intrastate gas (19 percent), and 13 percent was delivered by Transwestern. San Francisco and the northern part of the state was in part dependent on Canadian gas but also used gas from local wells. Nevada received just over half its supplies from El Paso and this pipeline served the southeast of the state. The north and central parts of the state were served by Northwest.

Region X, consisting of Idaho, Oregon and Washington, was supplied almost entirely by the Northwest Pipe Line, largely by imports from Canada.

Direct Sales of Natural Gas To MFBI in 1974 by Interstate Pipelines

Approximately 1087 major MFBI used natural gas in 1974. Of these, approximately 120 received at least part of their requirements by means of main line sales.

(A further 16 had had main line deliveries within the period 1970-73 but not in 1974.) The major MFBI were matched as far as possible with the customers listed in Table 4 in the Bureau of Mines Information Circula "Main Line Natural Gas Sales to Industrial Users";[1] where the point of delivery to a customer was at or close to the location of a major MFBI owned by that customer, it was presumed that delivery was made to the MFBI.

The 128 plants which were identified (12 percent of the total) used 329 trillion Btu's of gas out of about 2,900 trillion Btu's consumed by all major MFBI in the study - about 11 percent of total consumption.

Main line deliveries to these plants amounted to 419 Bcf of which about 75 percent was listed as firm gas. In the majority of individual cases, main line deliveries exceeded the FEA consumption figure, which implies that gas was used in other ways than as fuel for the major combustors in these plants - e.g., as fuel for combustors with capacity of less than 100 MMBtu/hr., or as feedstock.

In 29 cases (comprising 35 plants as some MFBI were grouped together in the same county), main line sales did not exceed or fall short of the MFBI consumption figure by more than 10 percent. Differences of this amount might be accounted for by such factors as variations in Btu content of the gas or in the exact period to which consumption relates.

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[1] U.S. Department of the Interior: IC 8688

In 12 cases (15 plants) consumption of gas exceeded main line deliveries by more than 10 percent, in a few cases by considerably more. These plants were apparently obtaining a considerable portion of their supplies from other sources; plants in the gas producing areas may have had supplies from local wells. In the case of two plants in the same county, possibly only one was served by main line and the other by a different supplier.

The extent to which the requirements of major MFBI combustors were met by main line deliveries varied considerably between regions and between states within regions. Schedule IV-15 shows by state, the pipelines delivering gas to MFBI and the amount delivered, the number of MFBI receiving main line gas and their consumption in major combustors, and the total number of gas-burning MFBI in the state along with their consumption in major combustors. The greatest proportionate use of main line service was in Region IV where 46 plants had deliveries. In Alabama 13 out of 24 MFBI had main line service, and in Mississippi 13 out of 16; gas consumption by these plants was in each case over two-thirds of the consumption by major MFBI combustors in the state. In Region VI, 35 plants had main line service, but smaller proportions of plants and of gas were involved than in the case of Region IV except for the state of Arkansas where 13 out of 15 MFBI had main line deliveries, and their combustors used over 50 percent of the MFBI gas consumption in that state. In Region V only 11 MFBI had main line deliveries, four in Illinois, none in Indiana, three in each of Michigan and Minnesota, and one in Ohio; and the gas so purchased was not a considerable part of supplies. Main line deliveries were important in Nebraska and Arizona.

Thirteen of the major pipelines made main line sales of gas to MFBI (pipelines wholly supplied by a major pipeline being included with the supplier).

United sold to the largest number of MFBI and sold a large amount of gas (73 Bcf) entirely in Regions IV and VI, mainly in Florida, Mississippi and Louisiana. The largest amount of gas sold direct to MFBI, however, was sold by, Arkansas-Louisiana Gas Co. and 89 percent of this was sold in Arkansas. Southern Natural was an important direct supplier in Region IV; El Paso in Arizona; and Mississippi River in Arkansas, Illinois and Missouri.

Individual Pipeline Supply Situations

The diverse consumption projections by URC discussed in earlier sections reflect not only different curtailment strategies but also variations in supply situations. Within interstate markets, the predominant source of supply has traditionally been interstate pipelines. Thus, this section discusses individual pipeline company supply situations. In light of LNG and SNG projects contemplated or operated by distributors, as well as the ability of some industrial concerns to obtain their own supply, it should be recognized that circumstances exogenous to the pipeline can affect industrial gas consumption in some local areas.

Schedule IV-16 sets out estimated requirements and curtailments by interstate pipelines for the year ending August 1977, compared with actual data for the year ended August 1976. Sheet 1 shows firm curtailments and Sheet 2 shows interruptible curtailments. As shown on Sheet 1, firm curtailments by interstate pipelines are projected to increase by nearly 800 Bcf for the coming year. However, net deliveries are projected to decline by only 411 Bcf, with the remainder of the increase in curtailments being attributable to increased requirements. The "increased" requirements may reflect assumed normal weather compared with warmer-than-normal weather for the actual period ended August 1976. With respect to interruptible sales (only a small portion of pipeline sales), requirements are shown to decline, but again, this may be related to weather adjustments. Interruptible deliveries are projected to decline by 33 Bcf.

Many of the individual pipelines depicted on Schedule IV-16 forecast approximately the same deliveries during the forthcoming year as during the past year. Notable among those which show continued declines in sales are United Gas Pipe Line, Transwestern Pipeline Co., Transcontinental Gas Pipe Line, Texas Gas Transmission, Tennessee Gas Pipeline, Southern Natural Gas, Northern Natural Gas Co., Natural Gas Pipeline Co., Midwestern Gas Transmission, Michigan-Wisconsin Pipe Line Co., and El Paso Natural Gas Co. The following table shows for these pipelines the primary states affected and the projected declines.

Pipeline	States Primarily Affected	Deliveries(Bcf) Year Ended		
		Aug. 1976	Aug. 1977	% Decline
l Paso	California, Arizona, New Mexico	1156	996	14%
ichigan-Wisconsin	Michigan, Wisconsin	774	735	5
idwestern	Illinois, Indiana	290	281	3
atural Gas Pipeline	Iowa, Illinois, Indiana	989	957	3
orthern Natural	S. Dakota, Minnesota, Nebraska, Iowa, Kansas	755	692	8
outhern Natural	Alabama, Georgia, S. Carolina	582	566	3
ennessee	Northeast, Tennessee, Alabama, Mississippi, Kentucky	1102	1077	2
exas Gas	Kentucky, Mississippi, Tennessee	599	552	8
ranscontinental	Delaware, D.C., Pennsylvania, New York, New Jersey, North & South Carolina	644	555	14
ranswestern	California	262	221	16
nited	Alabama, Florida, Louisiana	835	735	12

The above data with respect to interstate pipelines pertain to their sales predominantly to gas distributors and do not necessarily reflect shortages by end-users. The term curtailment in this context means the difference between the amounts of gas a pipeline is required to deliver, by contract or otherwise, and the amounts it is actually able to deliver. In the past, demand factors such as warm weather and the recession have acted to lessen the shortages at the end-user level.

However, FEA has analyzed the supply-demand situation at the end-user level, and the FEA data indicate that the above discussed pipeline curtailments are resulting in gas shortages. Schedule IV-17 shows FEA's projected industrial gas consumption and shortages by state for this winter compared with last winter. The decline in gas availability is more severe for the industrial sector than overall because of the large increase in residential-commercial consumption evidently predicated on weather colder than last year. The industrial shortage is also aggravated by the projected increase in gas requirements for this sector, apparently reflecting the improved economic climate. By reference to FEA's projections, the states experiencing the largest volumetric declines are California, Arizona, Indiana, and North Carolina.

The foregoing discussion pertains to the very near-term situation but is useful to verify that demand factors are no longer largely ameliorating the gas shortage. Over the period to 1980, it can reasonably be assumed that gas demand will continue to increase and thus reductions in gas supply will have a greater impact than in the past.

A key supply factor in interstate markets will be the deliverability of gas from existing reserves, which is shown on Schedule IV-18 for major pipelines. In total, production from existing reserves is shown to decline at an annual rate of over 10 percent. This is a severe decline, and reflects the rapid decline in deliverability for the older reservoirs which are more prevalent for interstate pipelines. As discussed earlier, interstate pipelines have not been successful in acquiring new reserves in recent years; pipelines showing annual declines of 10 percent or more include Columbia Gas Transmission, Transcontinental, Trunkline, Panhandle, Northern Natural, Arkansas-Louisiana, United, Transwestern and El Paso.

It is unlikely that these pipelines could acquire sufficient new reserves to offset these declines. In total, these pipelines would have to acquire over 10 Tcf of gas per year to maintain 1975 production levels. For those pipelines without access to offshore reserves the prospects for increased reserves additions are limited. The outlook for offshore reserves additions is now more favorable, but the lead time between offshore exploration and ultimate consumption of the resultant discoveries is 3 to 5 years.

For purposes herein, an interstate pipeline supply projection has been developed. This forecast assumes a 20 percent increase in reserves additions for 1977 to 1979, compared with the previous four years, and no further negative revisions. Coupled with the deliverability from existing reserves, this forecast shows a 4.4 percent annual decline in interstate pipeline supply between 1975 and 1980.

Thus, the outlook is for continued declines in interstate supply to 1980, albeit at a lower rate than in recent years. Coupled with increasing higher priority gas consumption, the result is diminishing industrial gas supply.